STATUS OF ELECTRIC POWER
IN THE MISSOURI RIVER BASIN

1981

mrbc

The Missouri River Basin Commission is the principal agency for the coordination of Federal, State, interstate, local, and nongovernmental plans for the development of water and related land resources in the area served by the Missouri River and its tributaries. As an independent regional commission, it also provides a forum in which States meet with Federal agencies to conduct and coordinate water and related land resources planning. The Commission Chairman is appointed by the President; its Vice Chairman is elected from among State members.

MRBC members are Colorado; Iowa; Kansas; Minnesota; Missouri; Montana; Nebraska; North Dakota; South Dakota; Wyoming; Department of Agriculture; Department of the Army; Department of Commerce; Department of Energy; Environmental Protection Agency; Federal Emergency Management Agency; Department of Health and Human Services; Department of Housing and Urban Development; Department of the Interior; Department of Transportation; Yellowstone River Compact Commission; Big Blue River Compact Administration. Canada and Missouri River Basin Indian Tribes are observers.

STATUS OF ELECTRIC POWER IN THE MISSOURI RIVER BASIN

- Planning
- Capacity
- Future Needs
- Environmental Quality
- Laws and Policies

MISSOURI RIVER BASIN COMMISSION
10050 Regency Circle, Suite 403
Omaha, Nebraska 68114

1980

PREFACE

Many individuals and officials are making decisions each day in the Missouri River Basin involving energy, land, and water resources. Generation of electric power, its distribution, and use probably have more impact on the area than any other form of energy at the present time. Many persons who are closely affiliated with the electrical power industry are well aware of the problems facing the basin and what is being done to solve those problems. However, those on the periphery of the industry engaged in related activities are often not aware of what is being accomplished or what is being planned for the future. A wide spectrum of the interested public must also be included in this second category.

This third Missouri River Basin Commission report on Status of Electric Power in the Missouri River Basin provides information on the status of electric power generation, future needs, and potentials for meeting these needs.

Information for this 1980 update is based upon available published information up to and including December 31, 1979. Content of this status report differs somewhat with information published in previous reports based upon information previously collected and analysis by the Federal Power Commission and Federal Energy Regulatory Commission. Due to U.S. Department of Energy reorganization and collection of information on a national basis, the publication of such information is delayed or not available. This is further complicated by the fact that available information is not collected by river basin boundaries. Information is collected and/or published by U.S. Department of Energy (10 regions), Federal Energy Regulatory Commission (five regions), Regional Electric Reliability Councils (nine areas), U.S. Department of Energy-Economic Regulatory Administration (30 regions), and 10 Missouri River Basin States. Detailed power plant information was not available on an individual basis necessary to tabulate MRB comparisons.

State and Federal members of the Missouri River Basin Commission provided information for sections of the report and on legislative activities.

It is planned to update and improve the Status of Electric Power Report biennially. Although presently limited to electric power, it is anticipated that the report could be expanded to include other forms of energy as more information becomes available in the future.

ACKNOWLEDGEMENTS

This report was prepared by the Missouri River Basin Commission staff under the overall direction of the Commission's Energy and Water Committee:

Charles Metzger (Chairman)	Department of Energy
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Several people and agencies were instrumental in the preparation of this report. Their assistance is gratefully acknowledged here.

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Terry Schlaht also provided additional information from the Missouri River Division at the U.S. Army Corps of Engineers.

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Chapter 1

THE EXISTING ELECTRIC POWER SITUATION

The widespread use of electricity is relatively new to the American life style. Nearly a third of the population can remember when many homes were without electricity and the service was unreliable. Moreover, our dependence on electricity has been brought into focus by recent fuel oil and natural gas shortages affecting the generation and the cost of electricity.

In response to cost increases and fuel shortages, power planning and coordination must be recognized as a necessary part of the effort to maximize cost savings, reduce duplication of facilities, and increase the reliability and adequacy of bulk power supply systems. In recognition of the benefits that can accrue from these joint activities, electric utility systems have, in increasing numbers, joined with neighboring systems to pursue these common goals. Within the Missouri River Basin, this effort is carried out by all segments of the industry, from large bulk power supplying systems having thousands of megawatts of generating capability to small municipal systems with little or no generating capability.

POWER PLANNING ARRANGEMENTS

National Reliability Council Power Planning

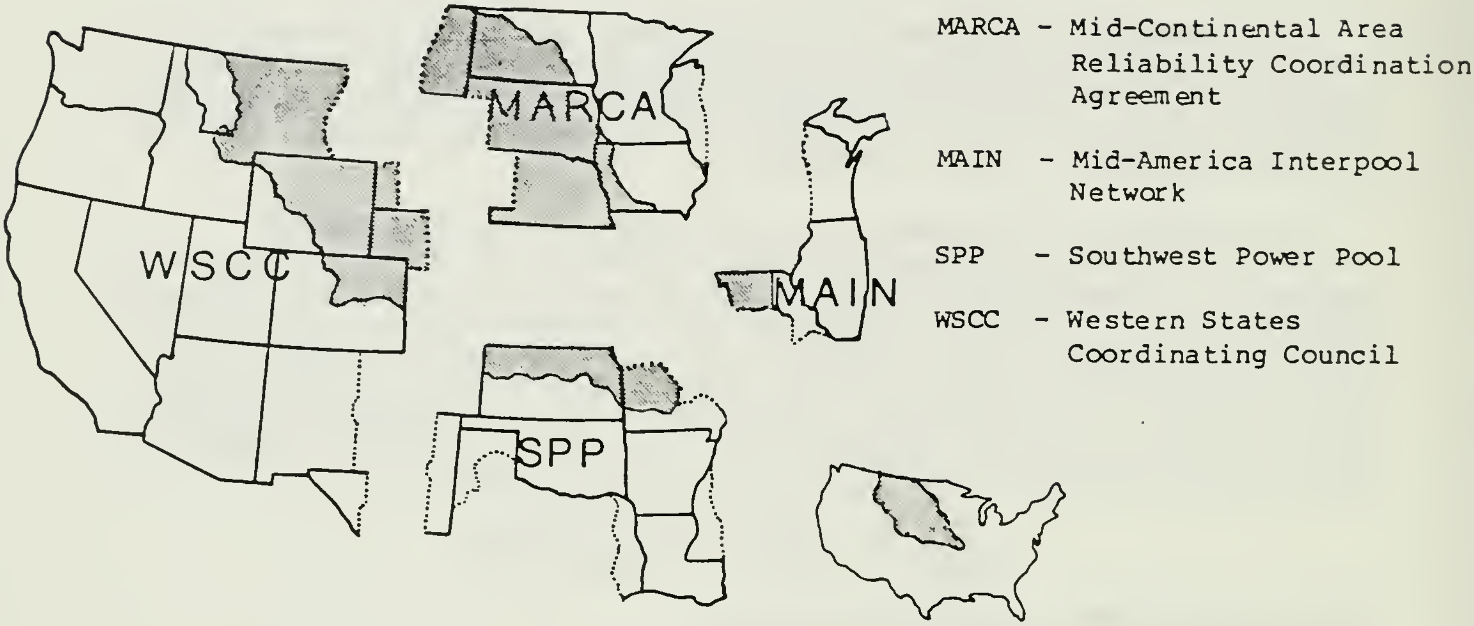
Most large-scale electric power planning in the United States and parts of Canada is conducted by the National Electric Reliability Council (NERC). The council, including its nine regional reliability councils, was formed voluntarily by the electric utility industry in 1968 to augment the reliability and adequacy of bulk power supply systems. NERC was created by, and represents, all sectors of the utility industry, public and private.

Portions of four of NERC's nine regional councils cover the Missouri River Basin as shown on figure 1. The Mid-Continent Area Reliability Coordination Agreement (MARCA) and the Western Systems Coordinating Council (WSCC) represent the larger areas within the Missouri River Basin. MARCA covers all of North Dakota, Iowa, and Minnesota; most of Nebraska and South Dakota; and a part of Montana within the basin. WSCC represents all of Wyoming and Colorado within the basin, portions of Montana and Nebraska, and the western edge of South Dakota. The Southwest Power Pool (SPP) includes the Kansas portion of the basin and the western half of Missouri. The Mid-America Interpool Network (MAIN) includes a portion of the State of Missouri in the southeast corner of the basin.

The purpose of the regional councils is to increase the reliability of bulk power suppliers whose operation would have a significant effect on the coordination, planning, and operation of electric generation and transmission facilities within each region. (A detailed description of each of the four regional councils and their membership within the Missouri River Basin can be found in Appendix 1.)

Figure 1

REGIONAL RELIABILITY COUNCILS, SUMMARY 1977



Federal-NERC Power Planning

In addition to regional member coordination, NERC also cooperates with the Department of Energy in planning for the Nation's future electric energy needs. This monitoring activity is conducted in part under the authority of a Federal Energy Regulatory Commission (FERC) order (NO. 3834, "Reliability and Adequacy of Electric Service") dated December 13, 1976.

One section of the order established a system for voluntary annual reporting to the Department of Energy of current and projected data for all components of the electric utility industry. To this end, 10-year projections of energy requirements are made each year. These data are summarized and reported by each of the nine regional electric reliability councils. Information submitted in their April 1 report each year generally includes those items listed in table 1.

Regional Power Planning

In addition to the planning/coordination groups and activities described above, the basin's individual utility systems participate in joint planning through one or more of the following 28 interstate and intrastate organizations or associations:

Table I

INFORMATION CONTAINED IN REGIONAL RELIABILITY COUNCIL REPORTS TO NATIONAL ELECTRIC RELIABILITY COUNCIL

1. Estimates of monthly peak loads for the first two years of the projection, estimates of summer and winter peak loads for the following eight years, monthly gross and net energy requirements for the first two years, and annual gross and net energy requirements for the following eight years.

2. A listing of the capacity of all existing facilities in the region and the new capacity requirements of facilities as committed or projected for each year of the next 10 years into the future. This includes in-service dates, locations, ownership, types of future generating units, primary fuel and capability for use of alternate fuels including length of time alternate fuel can be used, handling and storage capacity, and capacity exchanges with others at the time of summer and winter peak demands.

3. A tabulation for each year of the 10-year projection, showing the indicated capacity margins for reserves at the time of summer and winter peak loads, based on items (1) and (2) above, with an assessment of adequacy of reserves for the first five years of the projection. This assessment includes a statement of the criteria used to determine reserve requirements by the council or its appropriate subdivisions. It also includes an estimate of the magnitude of the capacity which will be unavailable for service due to scheduled maintenance or other known reasons at the time of summer and winter peak demand for the next five years.

4. A plan of the bulk power transmission network of the region in service at the time of the report (including interties with adjoining regions) and the general routing of facilities committed or tentatively projected for service within six years including identification of principal substations, operating voltages, and projected in-service dates. In addition, the transmission facilities projected for the balance of the 10-year period based on the best information available is requested.

5. A plotting and a description of the base case of the bulk power network of the region (or principal subdivisions) as it exists substantially at the time of reporting and as projected four to six years into the future; a tabulation based upon calculated operating limits specifying the transmission capability between the region and adjacent regions and between subdivisions of the region; a tabulation and brief statement on the results of a representative number of contingency cases studied and, similarly, results of stability analyses of the network, including the criteria adopted by the regional council relating to network stability.

6. A description of the principal communication and control systems operating or planned within the region and a listing of functions performed by such systems.

7. Information on the status of consultations with affected local communities and groups and status of applications to State or regional authorities for each transmission segment designed to operate at 230kV (nominal) or higher for which construction has begun or is scheduled to begin within two years from the date of the report.

8. Information on the following coordinated regional practices:

    a. Load shedding programs, including estimated steps of load reduction at various steps in declining frequency.

    b. Emergency power and shutdown facilities to prevent damage to equipment if a station loses system power.

    c. Power facilities available for unit startup in the event of total loss of system power.

    d. Availability of continuous power independent of system sources for communication and control facilities.

    e. Provisions for sustaining the operation of generating units on local loads.

    f. Programs for scheduling maintenance outages of generation and transmission facilities.

    g. Programs for the selection, setting, and maintenance of relays that affect the overall reliability of the interconnected network.

    h. Operating reserve policy.

9. A statement is requested on the percentages of the projected hydro, nuclear, and fossil-fueled capacity to be installed in the 11th through the 20th years.

10. A map showing the general configuration of the transmission network both within the region and the ties to adjacent regions, for the tenth year of the projection.

Basin Electric Cooperative (BAEP)
Colorado Power Pool (CPP)
Illinois-Missouri Pool (IL-MO)
Inland Power Pool (IPP)
Intercompany Pool (ICP)
Iowa Power Pool (IOPP)
Kansas Electric Cooperatives, Inc.
Kansas Municipal Energy Agency (KMEA)
Mid-Continent Area Power Pool (MAPP)
Missouri Basin Municipal Electric Cooperative Association (MBMECA)
Missouri Basins Municipal Power Agency (MBMPA)
Missouri Joint Municipal Electric Utility Commission (MJMEUC)
Missouri-Kansas Pool (MOKAN)
Missouri River Basin Systems Group (MBSG)
Nebraska Municipal Power Pool (NMPP)
Nebraska Pool (NEP)
North Iowa Municipal Electric Cooperation Association (NIMECA)
Northwest Power Pool (NWPP)
Pacific Northwest Coordination Agreement (PNCA)
Pacific Northwest Utilities Conference Committee (PNUCC)
Platte River Power Authority (PRPA)
Rocky Mountain Power Pool (RMPP)
South Dakota Municipal Power Agency (SDMPA)
South Iowa Municipal Electric Cooperative Association (SIMECA)
Southwest Power Administration (SPA)
Upper Mississippi Valley Power Pool (UMVPP)
Western Iowa Municipal Electric Cooperative Association (WIMECA)
Western Minnesota Municipal Power Agency (WMMPA)

Each organization exists for coordination, financing, and combined pooling and sharing of power produced by the individual group members. Member composition and specific functions and activities of each association are detailed in appendix 1.

BASIN TRANSMISSION NETWORK AND SYSTEM EXCHANGE CAPABILITY

In the same way that coordinated planning for electric energy development increases reliability and reduces cost, the interconnection of adjacent electric utility systems also represents an attempt to achieve more reliable and economical service. In addition to providing transmission within individual utility service areas, distribution systems are linked together by a network of interties that permit the exchange of power between the transmission facilities of different electric energy supply systems.

All of the bulk power supplying systems within the basin are interconnected through an extensive 115 kv, 230 kv, or 345 kv transmission network. Transmission along the western edge of the Missouri Basin is sparsely located and generally operates below the 230 kv level. Concentrations of both generation and population centers along the eastern edge of the basin have resulted in greater transmission concentrations and higher voltage levels in this area. Figure 2 shows the principal electric transmission lines currently serving the area.

The capability to transfer power between contiguous systems provides several major advantages that would not be available otherwise. First, the merger of delivery systems encourages the realization of scale economies common to large power generation facilities. Second, power can be transferred within regions and between regions to meet emergency power shortages. Third, transfers between systems permit the temporary purchase or exchange of electric energy at times of increased demand or excessive supply.

These types of power transfer capabilities exist for the Missouri River Basin's four regional reliability councils and their numerous member organizations, and in recent years, use of system exchange networks has increased. Among the reasons that have accounted for an increase in energy exchanges are transfers based on costs of production, fuel shortages in certain deficient areas, and excess fuel and generation facilities in areas with adequate generation reserves. More energy transfers are likely to occur in the future for similar reasons.

GENERATING PLANTS 30MW OR GREATER AS OF DECEMBER 31, 197

Plant No.	Utility	Plant Name	
1	MPC	Holter	
2	USWP	Canyon Ferry	
3	MPC	Rainbow	
4	MPC	Cochrane	
5	MPC	Ryan	
6	MPC	Morony	
7	USWP	Fort Peck	
8	MPC	Lewis & Clark	
9	MPC	Glendive	
10	MPC	Colstrip	
11	USWP	Yellowtail	
12	MPC	Frank Bird	
13	MPC	J.E. Corette	
14	PPC	Wyodak	
15	BHPL	Osage	
16	PPL	Dave Johnston	
17	USWP	Fremont Canyon	
18	USWP	Alcova	
19	USWP	Kortes	
20	USWP	Estes	
21	USWP	Flatiron	
22	USWP	Pole Hill	
23	PSC	Valmont	ST 282
24	PSC	Cabin Creek	
25	PSC	Ft. St. Vrain	
26	PSC	Ft. Lupton	
27	PSC	Cherokee	
28	PSC	Arapahoe	
29	PSC	Zuni	
30	TRGT	Republican River	
31	TRGT	Burlington	
32	USWP	Garrison	
33	UPA	Stanton	
34	CPA	Coal Creek	
35	BEPC	Leland Olds	
36	MIPI	Milton R. Young	
37	MDU	Hesket	
38	OTP	Jamestown	
39	BHPL	Kirk	
40	BHPL	Ben French	
41	USWP	Oahe	
42	USWP	Big Bend	
43	USWP	Ft. Randall	
44	USWP	Gavins Point	
45	BEPC	Spirit Mound	
46	NSP	Pathfinder	
47	CBPC	E.F. Wisdom	
48	IPS	George Neal	S
49	IPL	Council Bluffs	
50	CEIC	Summit Lake	
51	NPPD	Bluffs	
52	NPPD	Gentleman	
53	NPPD	Canaday	
54	NPPD	McCook	
55	NPPD	Hebron	
56	HAST	North Denver	
57	GRIS	C.W. Burdick	
58	NPPD	Columbus	
59	FREM	Fremont No. 2	
60	OPPD	Ft. Calhoun	
61	OPPD	Jones Street	GT 130 —
62	OPPD	North Omaha	
63	OPPD	Sarpy	
64	NPPD	Kramer	
65	OPPD	Nebraska City	
66	NPPD	Cooper	
67	LES	Lincoln J. Street	
68	LES	Rokeby	
69	NPPD	Sheldon	
70	NPPD	Hallam	
71	GMED	Goodland	
72	CEKP	Ross Beach	
73	CETV	Clifton	
74	KAPL	Abilene	ST 34 —
75	KAPL	Jeffrey	
76	KAPL	Tecumseh	ST 348 —
77	KACY	Kaw	
78	KACY	Quindaro	ST 335 —
79	KAPL	Lawrence	
80	KACP	La Cygne	S
81	ASEC	Unionville	
82	STLP	Edmond Street	
83	STLP	Lake Road	ST 151 —
84	MIPU	KCI	
85	INDN	Blue Valley	ST 115 —

MAJOR ELECTRIC FACILITIES
Within the Missouri River Basin

LEGEND

TRANSMISSION LINES

Existing		Authorized
	100-161 KV	
	230 KV	
	345 KV	
	500 KV and up	

GENERATING PLANTS

- Steam
- Nuclear
- Hydro
- Pumped Storage

0 50 100 Miles

Scale

Note: Transmission lines are generalized

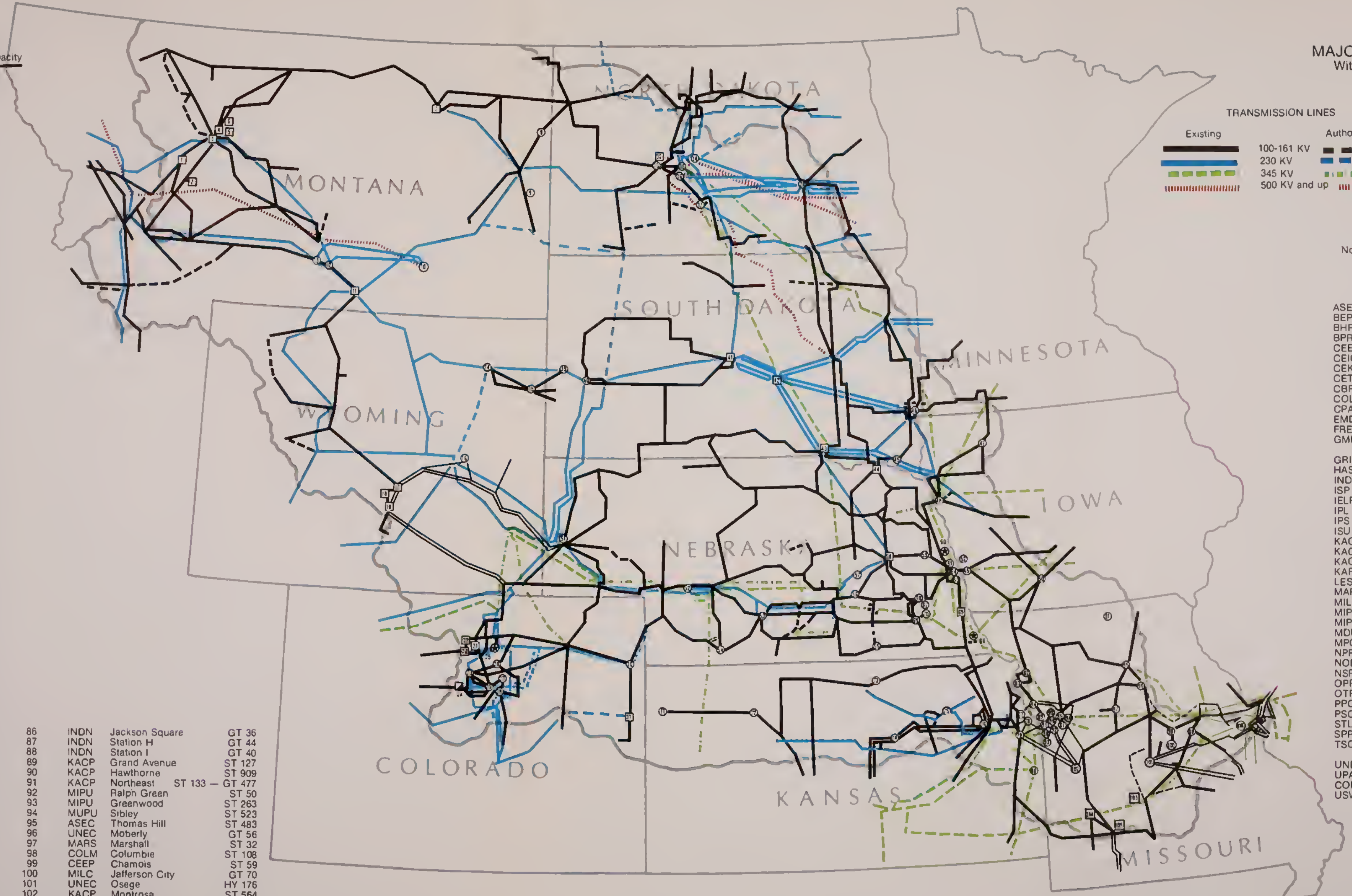
UTILITY CODE

ASEC — ASSOCIATED ELECTRIC COOP.
BEPC — BASIN ELECTRIC POWER COOP.
BHPL — BLACK HILLS POWER AND LIGHT
BPR — BONNEVILLE POWER ADMINISTRATION
CEEP — CENTRAL ELECTRIC POWER COOP.
CEIC — CENTRAL IOWA POWER COOP.
CEKP — CENTRAL KANSAS POWER COOP.
CETU — CENTRAL TELEPHONE AND UTILITY CORP.
CBPC — CORN BELT POWER COOP.
COLM — COLUMBIA
CPA — COOPERATIVE POWER ASSOCIATION
EMDE — EMPIRE DISTRICT ELECTRIC COMPANY
FREM — FREMONT
GMED — GOODLAND MUNICIPAL ELECTRIC DEPARTMENT
GRIS — GRAND ISLAND
HAST — HASTINGS
INDN — INDEPENDENCE
ISP — INTERSTATE POWER COMPANY
IELP — IOWA ELECTRIC LIGHT AND POWER COMPANY
IPL — IOWA POWER AND LIGHT COMPANY
IPS — IOWA PUBLIC SERVICE
ISU — IOWA SOUTHERN UTILITIES COMPANY
KACP — KANSAS CITY POWER AND LIGHT
KACY — KANSAS CITY
KAGE — KANSAS GAS AND ELECTRIC CO.
KAPL — KANSAS POWER AND LIGHT CO.
LES — LINCOLN ELECTRIC SYSTEM
MARS — MARSHALL
MILC — MISSOURI POWER AND POWER CO.
MIPI — MINNKOTA POWER COOP., INC.
MIPU — MISSOURI PUBLIC SERVICE CO.
MDU — MONTANA-DAKOTA UTILITIES CO.
MPC — MONTANA POWER CO.
NPPD — NEBRASKA PUBLIC POWER DIST.
NOEP — N W. ELECTRIC POWER COOP.
NSP — NORTHERN STATES POWER CO.
OPPD — OMAHA PUBLIC POWER DIST.
OTP — OTTER TAIL POWER CO.
PPC — PACIFIC POWER AND LIGHT CO.
PSC — PUBLIC SERVICE CO. OF COLORADO
STLP — ST. JOSEPH LIGHT AND POWER
SPRM — SPRINGFIELD
TSGT — TRI-STATE GENERATING & TRANSMISSION ASSN.
UNEC — UNION ELECTRIC CO.
UPA — UNITED POWER ASSOCIATION
COE — CORPS OF ENGINEERS
USWP — WATER AND POWER RESOURCES SERVICE

FIGURE 2.

GENERATING PLANTS 30MW OR GREATER AS OF DECEMBER 31, 1979

Plant No.	Utility	Plant Name	Unit Type Capacity
1	MPC	Holter	HY 40
2	USWP	Canyon Farry	HY 51
3	MPC	Rainbow	HY 36
4	MPC	Cochrane	HY 48
5	MPC	Ryan	HY 48
6	MPC	Morony	HY 46
7	USWP	Fort Peck	HY 165
8	MPC	Lewis & Clark	ST 50
9	MPC	Glandiva	GT 30
10	MPC	Colstrip	ST 716
11	USWP	Yellowtail	HY 252
12	MPC	Frank Bird	ST 69
13	MPC	J E. Corette	ST 173
14	PPC	Wyodak	ST 332
15	BHPL	Osage	ST 36
16	PPL	Dave Johnston	ST 788
17	USWP	Fremont Canyon	HY 48
18	USWP	Alcova	HY 36
19	USWP	Kortes	HY 36
20	USWP	Estes	HY 45
21	USWP	Flatiron	HY 74
22	USWP	Pole Hill	HY 32
23	PSC	Velmont	ST 282 GT 66
24	PSC	Cabin Creek	PS 300
25	PSC	Ft St Vrain	N 343
26	PSC	Ft. Lupton	GT 110
27	PSC	Cherokaa	ST 802
28	PSC	Arapahoa	ST 251
29	PSC	Zuni	ST 115
30	TRGT	Republican River	GT 225
31	TRGT	Burlington	GT 118
32	USWP	Garrison	HY 400
33	UPA	Stanton	ST 172
34	CPA	Coal Creek	ST 550
35	BEPC	Leland Olds	ST 657
36	MIPI	Milton R. Young	ST 720
37	MDU	Hesket	ST 100
38	OTP	Jamestown	GT 50
39	BHPL	Kirk	ST 32
40	BHPL	Ben French	GT 91
41	USWP	Oahe	HY 595
42	USWP	Big Bend	HY 464
43	USWP	Ft Randall	HY 320
44	USWP	Gavins Point	HY 100
45	BEPC	Spirit Mound	GT 120
46	NSP	Pathfinder	ST 75
47	CBPC	E F Wisdom	ST 38
48	IPS	Gaorga Neal	ST 1667
49	IPL	Council Bluffs	ST 781
50	CEIC	Summit Laka	GT 60
51	NPPD	Bluffs	ST 43
52	NPPD	Gentlamen	ST 650
53	NPPD	Canaday	ST 109
54	NPPD	McCook	CT 42
55	NPPD	Hebron	GT 43
56	HAST	North Danvar	ST 51
57	GRIS	C.W Burdick	ST 92
58	NPPD	Columbus	HY 42
59	FREM	Framont No. 2	ST 128
60	OPPD	Ft. Calhoun	N 502
61	OPPD	Jonas Street	GT 130 — ST 84
62	OPPD	North Omaha	ST 646
63	OPPD	Sarpy	GT 110
64	NPPD	Kramer	ST 136
65	OPPD	Nebraska City	ST 565
66	NPPD	Coopar	N 836
67	LES	Lincoln J. Streat	ST 31
68	LES	Rokeby	GT 66
69	NPPD	Sheldon	ST 219
70	NPPD	Hallam	GT 43
71	GMED	Goodland	IC 30
72	CEKP	Ross Baach	ST 36
73	CETV	Clifton	GT 85
74	KAPL	Abilene	ST 34 — GT 78
75	KAPL	Jeffray	ST 720
76	KAPL	Tecumseh	ST 348 — GT 52
77	KACY	Kaw	ST 161
78	KACY	Ouindero	ST 335 — GT 147
79	KAPL	Lawrence	ST 614
80	KACP	La Cygne	ST 1759
81	ASEC	Unionville	GT 46
82	STLP	Edmond Streat	ST 51
83	STLP	Laka Road	ST 151 — CW 85
84	MIPU	KCI	GT 40
85	INDN	Blue Valley	ST 115 — GT 61
86	INDN	Jackson Square	GT 36
87	INDN	Station H	GT 44
88	INDN	Station I	GT 40
89	KACP	Grand Avenue	ST 127
90	KACP	Hawthorne	ST 909
91	KACP	Northeast	ST 133 — GT 477
92	MIPU	Ralph Green	ST 50
93	MIPU	Greenwood	ST 263
94	MUPU	Sibley	ST 523
95	ASEC	Thomas Hill	ST 483
96	UNEC	Moberly	GT 56
97	MARS	Marshall	ST 32
98	COLM	Columbie	ST 108
99	CEEP	Chamois	ST 59
100	MILC	Jafferson City	GT 70
101	UNEC	Osege	HY 176
102	KACP	Montrosa	ST 564
103	COE	Harry Truman	HY 81
104	COE	Stockton	HY 45
105	SPRM	James River	ST 253
106	UNEC	Labadie	SP 2484



MAJOR ELECTRIC FACILITIES
Within the Missouri River Basin

LEGEND

TRANSMISSION LINES

Existing		Authorized
	100-161 KV	
	230 KV	
	345 KV	
	500 KV and up	

GENERATING PLANTS

- Steam
- Nuclear
- Hydro
- Pumped Storage

0 50 100 Miles

Scale

Nota Transmission linas are generelized

UTILITY CODE

ASEC — ASSOCIATED ELECTRIC COOP.
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FREM — FREMONT
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SUPPLY AND DEMAND - DECEMBER 31, 1979

The last Status of Electric Power Report published by the Missouri River Basin Commission provided information current through December 31, 1975. Since then, there has been a 31 percent increase in electric generation capacity in the basin bringing installed capacity at the end of 1979 to 30,990 megawatts.

During the same period, the number of electric generating plants had increased by one to 404 within the Missouri River Basin. These plants are of seven types: fossil-fired steam, nuclear steam, internal combustion (diesel), combustion turbine, combined cycle, conventional hydropower, and pumped storage hydropower (table 2).

While the total number of plants in service had increased by only one from 1975 to 1979, several plants were modified, taken out of service, and brought on line. Specifically, seven fossil-fueled steam plants and two conventional hydropower facilities were removed from service. Despite a net loss of nine plants, basinwide installed capacity for both plant types increased by 31 percent over 1975 levels.

Table 2

EXISTING ELECTRIC POWER INSTALLED CAPACITY
IN THE MISSOURI RIVER BASIN
1975 and 1979

Plant Type	Number of Plants		Installed Capacity (MW)	
	1975	1979	1975	1979
Fossil Fired Steam	88	81	15,723	20,508
Nuclear Steam	2	3	1,282	1,681
Internal Combustion (diesel)	217	217	940	1,050
Combustion Turbine	32	42	1,946	3,381
Combined Cycle	1	3	52	153
Conventional Hydropower	58	56	3,368	3,787
Pumped Storage Hydropower	1	2	300	408
Total	399	404	23,611	30,968

Source: Inventory of Power Plants in the United States - December 1979 - U.S. Department/Energy Information Agency

New plant additions between 1975 and 1979 included 1 nuclear steam, 10 combustion turbines, 2 combined cycle, and 1 additional pumped storage unit. The 14 additional plants produced a 57 percent increase in installed capacity for those 4 facility types. While no net increase occurred in the total number of internal combustion (diesel) plants, installed capacity increased from 990 MW to 1,050 MW.

Most electric power generated in the basin is produced at facilities with 30 MW or greater installed generating capacity. Table 3 provides a comparison of 1975 and 1979 installed capacity by plant type and facility size.

SUPPLY AND DEMAND - DECEMBER 31, 1979

The last Status of Electric Power Report published by the Missouri River Basin Commission provided information current through December 31, 1975. Since then, there has been a 31 percent increase in electric generation capacity in the basin bringing installed capacity at the end of 1979 to 30,990 megawatts.

During the same period, the number of electric generating plants had increased by one to 404 within the Missouri River Basin. These plants are of seven types: fossil-fired steam, nuclear steam, internal combustion (diesel), combustion turbine, combined cycle, conventional hydropower, and pumped storage hydropower (table 2).

While the total number of plants in service had increased by only one from 1975 to 1979, several plants were modified, taken out of service, and brought on line. Specifically, seven fossil-fueled steam plants and two conventional hydropower facilities were removed from service. Despite a net loss of nine plants, basinwide installed capacity for both plant types increased by 31 percent over 1975 levels.

Table 2

EXISTING ELECTRIC POWER INSTALLED CAPACITY
IN THE MISSOURI RIVER BASIN
1975 and 1979

Plant Type	Number of Plants		Installed Capacity (MW)	
	1975	1979	1975	1979
Fossil Fired Steam	88	81	15,723	20,508
Nuclear Steam	2	3	1,282	1,681
Internal Combustion (diesel)	217	217	940	1,050
Combustion Turbine	32	42	1,946	3,381
Combined Cycle	1	3	52	153
Conventional Hydropower	58	56	3,368	3,787
Pumped Storage Hydropower	1	2	300	408
Total	399	404	23,611	30,968

Source: Inventory of Power Plants in the United States - December 1979 - U.S. Department/Energy Information Agency

New plant additions between 1975 and 1979 included 1 nuclear steam, 10 combustion turbines, 2 combined cycle, and 1 additional pumped storage unit. The 14 additional plants produced a 57 percent increase in installed capacity for those 4 facility types. While no net increase occurred in the total number of internal combustion (diesel) plants, installed capacity increased from 990 MW to 1,050 MW.

Most electric power generated in the basin is produced at facilities with 30 MW or greater installed generating capacity. Table 3 provides a comparison of 1975 and 1979 installed capacity by plant type and facility size.

Table 3

INSTALLED GENERATING CAPACITY BY PLANT TYPE AND SIZE
1975 and 1979

	1975		1979	
	All Size Plants (MW)	Plants Over 25* (MW)	All Size Plants (MW)	Plants Over 30* (MW)
Fossil-Fired Steam	15,723	15,348	20,508	20,208
Nuclear Steam	1,282	1,282	1,681	1,681
Internal Combustion (Diesel)	940	0	1,050	59
Combustion Turbine	1,946	1,773	3,441	3,216
Combined Cycle	52	52	93	85
Conventional Hydropower	3,386	3,150	3,787	3,130
Pumped-Storage Hydropower	300	300	408	408
Total	23,611	21,915	30,968	28,787

*National Regional Reliability Council changed their reporting format from 25 MW to 30 MW, which slightly affects this comparison.

Source: Inventory of Power Plants in the United States - December 1979 - U.S. Department/Energy Information Agency

Figure 2 shows the location of all generating facilities with 30 MW or greater installed nameplate generating capacity in the basin in 1979, as well as the generalized location of transmission lines greater than 100 kv capacity.

Each year the U.S. Department of Energy, Energy Information Administration, conducts an inventory of power plants in the United States. According to this inventory, 55 additions in installed capacity are scheduled or planned within the Missouri River Basin for the period 1980 to 1990. The total capacity to be gained from these additions is 20,873 MW, a 67 percent increase over the existing 30,990 MW installed generating capacity. Over 75 percent of the projected capacity occurs from 34 steam turbine units totaling 16,238 MW. Table 4 is a list of the units scheduled or planned for the Missouri River Basin. (Statewide totals of existing and projected generating units and their capacities are listed in Appendix 2.)

THE FEDERAL POWER SYSTEM

Federally owned power generating plants and transmission facilities are an important component of the entire electric energy production and delivery network of the Missouri River Basin. In 1975, the Federal power plants accounted for 11.8 percent of the basin's generating capacity. By 1979, the Federal Power System contributed only 8 percent, or 2,744 MW of the basin's total installed generating capacity due to construction of large fossil-fueled facilities by non-Federal power interests.

Table 4

SCHEDULED OR PLANNED ADDITIONS IN INSTALLED GENERATING CAPACITY, 1980-1990

Plant Name/Principal Utility	Capacity	Type 1/	In-Service	Location State	Location County
Rawhide (PRPA) Platte River Power Authority	255	ST	1984	CO	Larimer
Pawnee (PSC) Public Service Company of Colorado	500	ST	1980	CO	Morgan
- Unsited (PSC) Public Service Company of Colorado	470	ST	1987	CO	--
	470	ST	1988	CO	--
- Unsited (TRGT) Tri-State Generating and Transmission Association	500	ST	1983	CO	--
	500	ST	1984	CO	--
	500	ST	1985	CO	--
- Unsited (APC) Association Power Coop.	550	ST	1985	IA	--
Nearman Creek (KACY) Kansas City	250	ST	1980	KS	Wyandotte
	500	ST	1982	KS	Wyandotte
Jeffery (KAGE) Kansas Gas and Electric Company	720	ST	1980	KS	Pottawatomie
	720	ST	1983	KS	Pottawatomie
	720	ST	1985	KS	Pottawatomie
Harry S. Truman (COE) Corps of Engineers	160	PS	1981	MO	Benton
Thomas Hill (ASEC) Associated Electric Coop.	670	ST	1982	MO	Randolph
Columbia (CWL) Columbia Water and Light Department	30	CT	1981	MO	Boone
	30	CT	1985	MO	Boone
	30	CT	1988	MO	Boone
Iatan (KACP) Kansas City Power and Light	728	ST	1980	MO	Platte
	726	ST	1987	MO	Platte
Greenwood (MIPU) Missouri Public Service Company	80	CT	1981	MO	Jackson
	115	CT	1983	MO	Jackson
Plant X (MIPU) Missouri Public Service Company	100	ST	1988	MO	--
	90	CT	1984	MO	--
	90	CT	1986	MO	--
Southwest (SWPA) Southwestern Power Association	250	ST	1985	MO	Greene
- Unsited (SPRM) City Utilities, Springfield, Missouri	70	CT	1982	MO	Greene
St. Joseph Light and Power Co. (STLP)	130	UN	1987	MO	--
	70	CT	1983	MO	--
Callaway (UNEC) Union Electric Company	1,192	NU	1982	MO	Callaway
	1,192	NU	1987	MO	Callaway
Colstrip (MPC) Montana Power Company	778	ST	1984	MT	Rosebud
and Consortiums (PSPL, PGE, WWP, PPL) Puget Sound Power and Light Company, Pacific Gas and Electric; Washington Power Company; Pacific Power and Light Company	778	ST	1985	MT	Rosebud
Resource 89 (MPC) Montana Power Company	350	ST	1999	MT	Cascade
Platte (NPPD) Nebraska Public Power District	110	ST	1981	NE	Platte
Hastings (NPPD) Nebraska Public Power District	75	ST	1981	NE	--
Gentlemen (NPPD) Nebraska Public Power District	650	ST	1981	NE	Lincoln
Boyd County (NPPD) Nebraska Public Power District	167	PS	1990	NE	Boyd
	167	PS	1990	NE	Boyd
	187	PS	1990	NE	Boyd
	167	PS	1990	NE	Boyd
	167	PS	1990	NE	Boyd
	187	PS	1990	NE	Boyd
	167	PS	1990	NE	Boyd
	167	PS	1990	NE	Boyd
Fossil Unit (NPPD) Nebraska Public Power District	650	ST	1986	NE	--
Antelope Valley (BEPC) Basin Electric Power Coop	438	ST	1981	ND	Mercer
	438	ST	1983	ND	Mercer
Coal Creek (CPA)	550	ST	1980	ND	McClean
Coyote (OTP) Ottertail Power Company	414	ST	1981	ND	Mercer
Laramie River (BEPC) Basin Electric Power Company	550	ST	1980	WY	Platte
	550	ST	1980	WY	Platte
	550	ST	1982	WY	Platte
Osage (BHPL) Black Hills Power and Light	100	ST	1984	WY	Osage
Wyodak (PPL) Pacific Power and Light Company	330	ST	1983	WY	Campbell

1/ NU - nuclear; ST - fossil steam; HY - hydro; CT - combustion turbine; PS - pumped storage; UN - unknown

Source: Inventory of Power Plants in the United States - December 1979,
U.S. Department of Energy/Energy Information Agency

Additional Federal hydroelectric facilities have not been built because the largest and most naturally favorable sites have already been developed and construction at the remaining sites has not been considered economically feasible. The escalating cost of fossil fuels and the Nation's emphasis on reducing foreign oil imports, moving toward energy independence, have forced a second look at the potential for additional hydroelectric capacity at existing facilities and a search for additional potential sites.

Development of these potential sites and retrofitting existing facilities will be more expensive than original costs of bringing major Federal plants on line. Projections for the Federal system do not include low-head hydroelectric development (see chapter 2, Regional Energy Studies), which could have important local significance.

NEW PLANT CONSTRUCTION COSTS

Electric plant types and capacities in existence and under construction in the Missouri River Basin include nuclear, conventional steam plants fueled by coal or lignite, combustion turbines, conventional hydroelectric and pumped storage hydroelectric. Sites for individual plants are selected based upon electricity demand; proximity to energy resources and water; and accesssibility to pipeline, rail and barge facilities to provide fuel delivery.

Two of the most important factors in deciding to construct a plant are the initial cost of construction and the annual cost of operation. It is typical that high initial cost plants generally have relatively low annual operating costs, and that plants with low initial costs have a relatively high annual operating cost.

Nuclear Steam-Electric Plants

By the end of 1977, 63 nuclear units were operating nationwide including 3 within the Missouri River Basin. One new plant has been completed within the basin since the 1975 status report was published. The average capital cost of nuclear plants put in operation in 1977 was $356/kW. It is estimated that the final cost of new nuclear units that were ordered in 1977 will be more than double the 1977 costs. Projected costs are expected to reach $829/kW by the time these nuclear steam-electric plants are completed.

Thermal Electric Plants

As with nuclear plants, the construction and operating cost of thermal electric (fossil-steam) power plants has been steadily increasing. The cost for large capacity (300 MW) thermal electric plants nationwide has risen from an average of $109/kW installed capacity in 1967 to $275/kW in 1977. Three major new plants were reported on line in 1978 by the U.S. Department of Energy (table 5).

Table 5

ESTIMATED COST OF NEW FOSSIL STEAM GENERATING FACILITIES
1978

Plant Name	Utility	Size/MW	Cost/kW
Wyodak	Pacific Power & Light Co.	331.9	---
Council Bluffs	Iowa Power & Light Co.	331	$435.11
Jeffrey	Kansas Power & Light Co.	720	$486.77

Source: Steam Electric Plant Construction Cost and Annual Production Expenses 1978. U.S. Department of Energy/Energy Information Agency 033/(78)

Hydroelectric Plants

The investment necessary for a new hydroelectric project varies greatly according to the type of project, its size and location, the cost of land required, and the cost of relocations of highways, railroads, buildings, and other existing development. On the average, the cost per kilowatt is substantially higher for conventional hydroelectric plants than for thermal electric plants. On the other hand, hydroelectric plant production expenses are much lower principally because no fuel is required and other operating and maintenance costs are usually less. Nationwide, the cost of major plants in 1977-1978 ranged from $388/kW to $503/kW.

The economic impact of continued reliance upon unstable supplies of foreign oil and the increased cost of fossil-fuels have rekindled interest in building hydrolectric power plants. While many studies have been initiated (see Regional Energy Studies, chapter 2), and some construction is planned in the future, no major hydroelectric plants were reported to have come on line in the basin since the 1975 status report.

Pumped-Storage Projects

Pumped-storage installations are of two general types: (1) those which use both pumped water and natural run-off for generation, and (2) those which are exclusively pumped-storage and generate power by recirculating the water between a lower and an upper reservoir.

The pumped-storage method of utilizing water power for peaking capacity is selected on the basis of low initial investment cost and the ability to convert low-cost off-peak pumping energy to high-value peaking energy. Pumped-storage plants have the same favorable operating characteristics as conventional hydroelectric plants—rapid start-up and loading, long life, and low outage rates.

Pumped-storage projects are usually more economically developed at sites having high heads. The highest head of any existing pumped storage development in the United States is about 1,200 feet at the Cabin Creek project in Colorado located within the Missouri River Basin (figure 2). Factors that contribute to the economic attractiveness of pumped-storage developments are a relatively low initial investment and their ability to provide peak capacity. This reduces the need for thermal units to meet part of the peak demand and decreases their cycling which improves their durability and efficiency. Costs of development depend largely upon site, topograhy, and geological conditions. Reservoirs, dams, waterways, pump-turbine, and motor-generator equipment are the most costly features, representing approximately 70 to 75 percent of the total cost.

Within the basin, the 160 MW Harry S. Truman facility is a pumped-storage project and is undergoing turbine bearing modification. The Truman Project is scheduled for in-service operation in April 1981. Table 4 shows pumped-storage units scheduled or planned within the basin during the period 1980-1990.

THE EFFECTS OF THE RECENT DROUGHT ON MISSOURI RIVER MAIN STEM HYDROELECTRIC POWER PRODUCTION

Energy generation from the Missouri River main stem projects was slightly above long-term norms in 1980 in spite of drought-level inflows being experienced. Present system operation criteria allow for full-service navigation releases to be continued during the first year of a drought when the reservoir system is somewhat below full carryover storage capacity. Estimated energy production for 1981 is projected at 9.8 billion kWh. The 1981 forecast level of energy production equals the long-term average energy generation under present levels of depletion. However, if below normal inflows are experienced during 1981, the generation will be below 9 billion kWh. Further reduction in generation would be expected during 1982 if drought conditions continue.

Chapter 2

POWER RESOURCES FOR FUTURE DEVELOPMENT

This chapter projects nationwide growth in total energy needs and electrical generation from base year 1978 to year 2000. In addition, it contains a discussion of recent regional energy studies, and a listing of possible additions to main stem hydropower currently under active study by the Corps of Engineers.

PROJECTIONS OF ELECTRIC POWER DEMAND

The nationwide projections discussed in this report have been developed by Harza Engineering Company and are contained in a report entitled "Phase II—Future Electric Power Demand and Supply" which is an appendix to the National Hydroelectric Study report prepared by the U.S. Army Institute for Water Resources. For comparative purposes, three nationwide projection levels have been drawn to define a reasonable range of future demands. From these three projections, a "median" projection has been drawn to represent future power and energy demand and can be utilized to determine the demand for a region or subregion. Each projection used in this report was analyzed in a simplified manner considering population, per capita energy consumption, and load factor. Factors such as income, population changes, age distribution, unemployment rates, leisure time, and climatic affects—although they do affect energy demand--were not analyzed.

Table 6 provides a summary of each of the four projections for the years 1985, 1990, 1995, and 2000. A more detailed description of each projection and how it was derived follows.

Projection I (Utilities)

Based on utility projections, each NERC region annually forecasts electric energy demand for the next 10 years and provides "conceptual planning" projections for the subsequent 11 to 20 years. The reports filed by the utilities through the Regional Electric Reliability Councils to the Department of Energy on April 1, 1979, are the source for this projection. In these reports the utilities forecast energy demand and peak demand for the 1979-1988 period. The "conceptual planning" projections for the 1989-1998 period include peak load but not energy demand.

The methodology used by individual utilities to forecast future demands varies from a general extrapolation of historical trends to detailed econometric models by consumer categories. (Econometrics is the combining of economic and statistical techniques to estimate future production.)

Projection I peak demands shown in table 6 for the years 1985, 1990, and 1995 are those determined by the utilities in the Reliability Council reports. The peak demand in the year 2000 shown in table 6 is extrapolated from these data assuming continuation of the 1995-1998 peak demand average growth rate. The 1985 energy demand is also forecast by the utilities. Beyond 1985, energy forecasts are calculated from the peak demands using the assumed load factors which follow.

The annual load factor for 1985 is computed using the annual energy and peak demand projected by the utilities. The 1990 through 2000 annual load factors are

Table 6

ELECTRIC POWER DEMAND
UNITED STATES SUMMARY
(1978-2000)

	1978	7-YEAR GROWTH RATE* (Percent)	1985	5-YEAR GROWTH RATE* (Percent)	1990	5-YEAR GROWTH RATE* (Percent)	1995	5-YEAR GROWTH RATE* (Percent)	2000	22-YEAR OVERALL GROWTH RATE* (Percent)
POPULATION (THOUSANDS)	219170.	1.0	234210.	1.0	245826.	.7	254586.	.7	263710.	.8
PROJECTION I (Utilities)										
PER CAPITA CONSUMPTION (MWH)	10.1	4.0	13.3	3.3	15.7	3.5	18.6	3.3	21.8	3.6
TOTAL DEMAND (THOUSAND GWH)	2210.4	5.0	3110.1	4.3	3847.8	4.2	4727.4	4.0	5750.7	4.4
PEAK DEMAND (GW)	397.7	5.1	564.9	4.7	711.0	4.2	875.3	4.0	1066.5	4.6
PROJECTION II (Institute for Energy Analysis)										
PER CAPITA CONSUMPTION (MWH)	10.1	2.7	12.1	2.6	13.8	2.6	15.6	2.6	17.8	2.6
TOTAL DEMAND (THOUSAND GWH)	2210.4	3.6	2836.9	3.6	3385.6	3.3	3983.9	3.3	4688.8	3.5
PEAK DEMAND (GW)	397.7	3.8	515.3	4.0	625.6	3.3	737.6	3.3	869.6	3.6
PROJECTION III (consensus)										
PER CAPITA CONSUMPTION (MWH)	10.1	4.6	13.8	4.0	16.8	3.3	19.7	3.2	23.0	3.8
TOTAL DEMAND (THOUSAND GWH)	2210.4	5.5	3225.7	5.0	4119.6	4.0	5015.1	3.9	6077.2	4.7
PEAK DEMAND (GW)	397.7	5.7	585.9	5.4	761.2	4.1	928.6	3.9	1127.0	4.8
PROJECTION IV (median)										
PER CAPITA CONSUMPTION (MWH)	10.1	3.9	13.2	3.3	15.5	3.2	18.2	3.0	21.0	3.4
TOTAL DEMAND (THOUSAND GWH)	2210.4	4.9	3087.9	4.3	3819.0	3.9	4629.3	3.7	5550.9	4.3
PEAK DEMAND (GW)	397.7	5.0	560.9	4.7	705.7	4.0	857.2	3.7	1029.4	4.4
MARGIN (PERCENT)			28.4		24.9		24.1		23.8	
RESOURCES TO SERVE DEMAND (GW)			720.1		881.2		1063.9		1274.3	
LOAD FACTOR (PERCENT)	63.4		62.8		61.8		61.7		61.6	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

assumed to be equal to the average of the 1985-1988 annual load factors computed from the utility forecasts. This is based on the fact that, in most cases, the utility load factor forecasts for the next decade will only change slightly. The tendency for an increase in load factor may be offset to some degree by use of other energy sources such as solar, wind, geothermal, or cogeneration at the customer site. However, these sources are not expected to reduce the energy demand on electric utilities and decrease the load factor because they will not reduce the peak demand appreciably. Various load management programs, incremental rate schedules, slower rate of growth of peak loads, and certain other factors could increase the load factor; but at this time, there is no basis for saying that forces tending to change load factor in one direction are greater than those tending to change it in the opposite direction.

Analyzing the electricity projections made by the utilities during the past decade, a clear downward trend in their forecast is evident. The latest utility forecasts appear to reflect the changes in economic and demographic growth as well as other parameters such as implementation of more energy efficient technologies and conservation measures. For example, table 7 compares the 1985 and 1995 peak demand projections for each NERC region as reported in the 1976 and 1979 reports. Except for the MARCA region, all 1985 projections have been reduced between 10 and 20 percent. The projections for the 1995 peak demand show a greater difference with 20 to 36 percent reduction.

Table 7

COMPARATIVE PEAK DEMAND PROJECTIONS
FOR NINE NERC REGIONS

	1985			1995		
NERC Region*	1976 Report (MW)	1979 Report (MW)	Change (%)	1976 Report (MW)	1979 Report (MW)	Change (%)
ECAR	100,774	80,165	-20.4	216,300	137,900	-36.2
ERCOT	46,203	40,712	-11.9	82,419	65,827	-20.1
MAAC	50,150	40,426	-19.4	78,490	52,016	-32.1
MAIN	56,539	46,636	-17.5	102,400	71,644	-30.0
MARCA	30,501	29,182	- 4.3	48,460	47,776	- 0.1
NPCC	51,662	44,852	-13.2	81,535	59,720	-26.7
SERC	144,737	121,920	-15.8	259,617	195,802	-24.6
SWPP	69,165	58,966	-14.7	141,827	102,701	-27.6
WSCC	110,051	98,364	-12.5	181,000	142,957	-21.0
TOTAL	659,782	561,223	-14.9	1,192,048	876,343	-26.5

*Abbreviations as follows:
ECAR - East Central Area Reliability Coordination Agreement.
ERCOT - Electric Reliability Council of Texas.
MAAC - Mid-Atlantic Area Council.
MAIN - Mid-America Inter-pool Network
MARCA - Mid-Continent Area Reliability Coordination Agreement.
NPCC - Northeast Power Coordination Council.

SERC - Southeastern Electric Reliability Council
SWPP - Southwest Power Pool
WSCC - Western Systems Coordinating Council.

While the 1980 NERC Report was not available as a source for this report, comments from NERC indicate that the 1980 projections reflect a slow down in future power and energy demand. For example, the peak demand projection for the year 1987 in the 1979 NERC forecast (approximately 610,000 MW) is now expected to occur in 1989 instead.

Projection II (IEA)

Projection II is derived from the forecast made by the Institute for Energy Analysis (IEA) at the Oak Ridge Associated Universities in September 1976. The IEA study considered three projection levels and was chosen because it reflects a low-growth rate of the Nation's future energy demands based on energy-saving technologies. The three projections included in the IEA study were: (1) a reference base case which does not reflect efficiency improvements or real price increases; (2) a "high" and a "low" projection based on energy-saving technologies. Even the "high" projection in this study is much lower than most previous estimates of energy demand in the United States to the year 2010. The main finding of the IEA study was that both the Gross National Product (GNP) and the U.S. energy demand are likely to grow significantly more slowly than has been assumed in most analyses of energy policy.

The IEA study projects several parameters such as: economic and demographic growth, the labor force and productivity, total energy demand, and electricity demand. It has also singled out four specific available and potential energy-saving technologies which could be used for various services and processes in the United States' economy but which have not presently been uniformly or widely used. These four energy saving technologies are the following:

(1) New building construction of improved energy-conserving design using heat pump system and a heat storage tank for heating and cooling.

(2) Smaller and lighter-weight automobiles and service trucks with more efficient engines and transmissions and having less steel and aluminum.

(3) Improved industrial boiler design and heat recovery processes in the various energy-intensive manufacturing industries. Fuel would be shifted from oil and gas to the direct use of coal and nuclear heat, or to electricity.

(4) Electric load-level switching for the small consumer of electricity as well as for the large consumer. Although this would not save energy, it would reduce peak loads and save the high cost of peaking power.

The major energy-saving technologies suggested above could be timed to coincide with the normal retirement of capital items when the technologies are cost effective in each case. If these technologies were increasingly adopted during the next 35 years under price or supply pressures, tax differentials, or government intervention they would have an impact on energy demand and/or dollar savings. The use of energy-saving technologies (with specific sector strategies as in table 8)

Table 8

MAJOR ENERGY-SAVING TECHNICAL STRATEGIES

1. Improved household and commercial heating, cooling, hot water, lighting and appliances.

   a. Construct new buildings with better design and insulation standards and with electric heat pump systems and a heat storage tank. Cut average heat losses by 30 percent and fuel requirements by 50 percent on all new construction. Retrofit existing buildings to cut fuel requirements by an average of 69 percent. Shift oil and gas-fired systems to be retired to electric heat pump systems.

   b. Improve water heater insulation and eliminate severe pipe losses. Improve large appliance efficiencies. Fuel requirements decrease to 5 percent by 1985, 8 percent by 2000, and 10 percent by 2010 for hot water, cooking, refrigeration, and clothes drying.

   c. Improve household and commercial electric lighting and small electric appliance efficiencies by 5 percent by 1985, 8 percent by 2000, and 10 percent by 2010.

2. Industrial process steam and heat and electric drive.

   a. Improve industrial boiler design and heat recovery processes, cutting fuel consumption to 15 percent by 1985, 25 percent by 2000, and 30 percent by 2010. Shift industrial boilers for low-temperature heat and steam from oil and gas to the direct use of coal and nuclear heat or to electricity, possibly with support from solar energy.

   b. Improve iron/steel processes and aluminum processes to decrease average energy use per ton by 5 percent by 1985, 10 percent by 2000, and 12 percent by 2010.

   c. Improve industrial electrical lighting efficiencies by 10 percent by 1985, 17 percent by 2000, and 20 percent by 2010.

3. Electricity generation and distribution.

   a. Decrease expensive electricity generation peak load requirements by implementing load-leveling technologies for the small consumer as well as the large one. This would include heat storage and heat pump systems in the household, commercial, and industrial sectors, and automatic load level switching for hot water and large appliances in the household and commercial sectors.

   b. Use cogeneration of electricity and process steam and heat where economical. Encourage solar, geothermal, waste, and wind energy systems in those geographic areas where such systems are plausible.

3. Electricity generation and distribution.

   a. Decrease expensive electricity generation peak load requirements by implementing load-leveling technologies for the small consumer as well as the large one. This would include heat storage and heat pump systems in the household, commercial, and industrial sectors, and automatic load level switching for hot water and large appliances in the household and commercial sectors.

   b. Use cogeneration of electricity and process steam and heat where economical. Encourage solar, geothermal, waste, and wind energy systems in those geographic areas where such systems are plausible.

would reduce the total U.S. energy requirements and would shift the fuel demands from oil and gas to electricity and the direct industrial use of coal, nuclear, or solar heat.

The electric energy and demand assumptions for the three projections for the year 2010 discussed in the IEA study are reflected in table 9 for the transportation, residential, commercial, and industrial sectors. The reference base case does not include efficiency improvements or real price increases. The high and low scenarios consider increased efficiency improvements in all but the transportation sector.

Table 9

ELECTRIC ENERGY AND DEMAND ASSUMPTIONS FOR THE YEAR 2010
(quads or 10^{15} Btu)

	Reference Base Case Electricity	High Scenario		Low Scenario	
		Electricity	% of Ref. Case	Electricity	% of Ref. Case
Transportation	0.5	0.5	100	0.5	100
Residential	31.6	26.0	82	16.9	53
Commercial	21.3	17.4	82	10.3	48
Industrial	44.0	28.5	65	27.8	63
Total	97.4	72.4	74	55.5	57

Detailed data is not readily available for the year 2000; however, sufficient data is furnished in the IEA study to permit load growth estimates for intermediate years. Based on these scenarios, the annual per capita electric energy consumption growth rate in the United States is projected to be 3.8 percent in the "high" scenario and 2.6 percent in the "low" scenario for the period 1985-2000. For this report, the "low" scenario was selected and used in table 6 as Projection II (IEA).

The low growth rate reflects the lower economic growth anticipated by IEA over this period which is predicated upon the following factors: (1) a low fertility rate (1.7 births per woman), (2) a slower rise in labor force, (3) a rate of 2.0 percent of average annual growth of labor productivity, (4) 12.7 percent annual growth rate in GNP, (5) higher efficiencies and improvement factors in generators, motors, appliances, transmissions, etc., (6) accelerated implementation of conservation measures and energy saving technologies, and (7) the effect of higher energy prices (the average electric energy price being twice the price in the reference base case).

The growth percentage rate may vary from one area of the country to another and data on a regional basis is not readily derivable from the IEA study. In Projection II (IEA), the annual per capita electric energy consumption growth rate is assumed to be 2.6 percent for all subregions of the United States for the entire period 1978-2000.

In table 6, the 1978 per capita energy consumption data is the base condition. Future energy demand is computed from the base using the assumed 2.6 percent

growth rate in per capita consumption and the adjusted OBERS population projections. The peak demand is computed from the energy value using the utility load factors derived in Projection I (utilities).

Projection III (Consensus)

Projection III is based on the "Consensus Forecast of U.S. Electricity Demand" as derived by a group of Federal and private economists (table 10). These forecasts include both conservation-oriented forecasts and forecasts based on historical growth.

Table 10

LIST OF CONSENSUS FORECASTERS

	Forecaster	Date of Forecast
1.	NASA/ASEE TERRASTAR	September 1973
2.	Environmental Protection Agency	November 1973
3.	U.S. Atomic Energy Commission (D.L. Ray))	December 1973
4.	Ford Foundation (technical fix)	Early 1974
5.	Ford Foundation (zero energy growth)	Early 1974
6.	U.S. Atomic Energy Commission (Office of Planning and Analysis)	February 1974
7.	L.T. Blank and R.I. Riley	March 1974
8.	Council on Environmental Quality	March 1974
9.	MIT (Hudson Jorgenson)	May 1974
10.	MIT (judgmental)	May 1974
11.	National Academy of Engineering	May 1974
12.	NASA/ASEE MEGASTAR	September 1974
13.	Federal Energy Administration Project Independence	December 1974
14.	ERDA (Office of Planning and Analysis)	February 1975
15.	E. Teller	April 1975

The conservation-oriented forecasts listed in table 10 assumed that a determined national effort to reduce demand for energy through application of energy-saving technologies would be successful and that continued high world oil prices would keep domestic energy prices high, resulting in lower demand. Some forecasters in this group even projected zero per capita energy growth rate by the year 2000. The average of the conservation-oriented forecasts for total U.S. energy demand in the year 2000 was 132 quadrillion BTU (quads) or was approximately 15 percent lower than the average of earlier forecasts of 150 quads.

For the "Consensus Forecast," electricity demand was correlated as a function of the percentage of total energy demand for both the historical growth and the conservation-oriented forecasts. The average of these results represents the "consensus" forecast and is summarized in table 11. The per capita electric energy consumption was computed from the electrical generation projections and the population obtained from the OBERS adjusted population projections. The per capita consumption rate computed for the period 1980-1985 was used for the total period 1978-1985.

Table 11

CONSENSUS FORECAST OF NATIONAL ELECTRICITY DEMAND

	1980	1985	1990	1995	2000
Total Energy (10^{15} Btu)	88	100	110	121	132
Utility Electricity (percent of total)	30.7	35.4	39.2	43.6	48.4
Electrical Generation (10^{15} Btu)	27.0	35.4	43.1	52.8	63.9
Heat Rate (Btu/kWh)	10,800	10,800	10,300	10,300	10,300
Electrical Generation (kWh x 10^9)	2,500	3,270	4,200	5,100	6,200
Population (10^6)	223	234	246	254	264
Per Capita Consumption (kWh/capita)	11,210	14,000	17,070	20,080	23,500
Per Capita Growth Rate (%)		4.5	4.0	3.3	3.2

The computed growth rates, which indicate a moderate increase in electricity demand, were used in this study to compute the electric energy in Projection III after 1978. The procedures to calculate energy and peak demand included in table 6 for each projection year are the same as those described in Projection II. Also, as applied to Projection II, the per capita electricity consumption growth rates are not readily available by regions or subregions. In this study, the national per capita consumption growth rates were applied equally to all regions and subregions. It is recognized that there are variations in per capita growth rates from one region to another, but the lack of regional data in the Consensus Report makes it difficult to adjust for such variations.

Projection IV (Median)

Projections I, II, and III represent reasonable ranges of growth in future electricity demand. Each of these projections consider methods for reducing future energy demands. The projections incorporate the impact of various demand reducing methods. The latest utility forecasts (Projection I) incorporate the impact of conservation measures into other projections. This is evident when compared to previous forecasts by the utilities. From the information available, it is difficult to explicitly identify the relative importance of the various measures in each consumer category (residential, commercial, and industrial) for all regions of the country. Projections II and III also reflect the impact of the conservation measures discussed. From these three projections, a "median" projection was calculated by Harza Engineering Company in the "Phase II—Future Electric Power Demand and Supply"

report. This projection is considered to be representative of future power and energy demand of a region or subregion.

The "median" forecast (Projection IV) was determined by obtaining the median energy demand from Projections I, II, and III and applying the base load factor utilized by the individual utilities in Projection I. Since the utilities base load factor was utilized in computing the energy demand for projection IV each subregion's and region's energy demands must be summed to arrive at the total United States energy demand for the "median" forecast.

The peak energy demand was also computed using the median energy demand from Projections I, II, and III and the load factor derived from Projection I made by the utilities. The per capita energy consumption was determined by dividing the total energy demand by the population.

REGIONAL ENERGY STUDIES

Several regional energy studies have been undertaken within the Missouri River Basin. The U.S. Army Corps of Engineers has conducted two regional energy studies, the "Umbrella Study" and the National Hydroelectric Survey. The Bureau of Reclamation completed the Small Hydroelectric Development Study and is working on a Solar-Wind Project.

U.S. Army Corps of Engineers

Missouri River - South Dakota, Nebraska, North Dakota, Montana (Umbrella Study)

In August 1977, the Missouri River Division of the Corps of Engineers completed a report on water resource developing including hydropower, entitled: "Missouri River, South Dakota, Nebraska, North Dakota, Montana Review Report for Water Resources Development," (Review Report of 1977). The report recommended that the Corps of Engineers be authorized to conduct the first phase of advanced engineering and design studies of (1) a pumped storage facility in Gregory County, South Dakota, and (2) additional hydropower units with reregulation structures at Fort Peck Dam in Montana and Garrison Dam in North Dakota.

The report also concluded that further preauthorization studies should be conducted to consider the potential for additional hydroelectric units at Oahe and Fort Randall Dams and the potential long-range need for pumped storage development in addition to the potential at the Gregory County site.

The 1977 report was returned by the Secretary of the Army requesting additional studies to support a recommendation for a construction authorization. He noted that the type of pumped storage project considered for the Gregory County site had never before been recommended to the Congress for construction by the Corps of Engineers. He requested that such a recommendation be supported by a discussion of the decision rationale and supporting documentation. The return of the report provides the Corps of Engineers an opportunity to conduct additional studies to address the remaining unresolved issues and develop more detailed estimates of the costs, benefits, and impact of the potential hydropower additions.

Other studies for the potential Gregory County pumped storage facility have been initiated, and an interim report is scheduled for FY 1982. Studies of the additional units with regulation structures at Fort Peck and Garrison Dams will be

initiated in FY 1981, with completion of a survey scheduled in FY 1984 to address the potential for both additional units and additional pumped storage.

Possible near-term recommendations include:

1. The conversion of two flood control tunnels at Fort Peck, Montana, and three flood control tunnels at Garrison, North Dakota, for the production of 185 MW and 272 MW of additional power capacity, respectively.

2. The construction of a 1,180 MW pumped-storage hydropower site adjacent to Lake Francis Case in South Dakota, known as the Gregory County Site, to utilize available off-peak energy sources for pumping.

Long-term recommendations include:

1. Deferral of possible long-term power additions of 144 MW at Oahe Dam and 282 MW at Fort Randall Dam for restudy until less uncertainty exists on the amount of future water depletions.

2. Deferral of a pumped-storage site adjacent to Lake Sakakawea, North Dakota, with a capacity of more than 1,000 MW, pending long-term development of alternative energy supplies required for off-peak pumping cycles.

3. More detailed studies of a large number of pumped-storage sites having sufficient hydraulic heads for 500 MW or greater production that have already been studied under reconnaissance-type studies. Further analysis will be required during the mid-1980's to determine the long-term feasibility of these potential sites.

National Hydroelectric Survey

Section 167 of the 1976 Water Resources Development Act (P.L. 94-587) directed the Army Corps of Engineers to undertake a National Hydropower Study to identify remaining hydropower potentials. The primary objectives of the study are to determine the need for hydropower, define the physical limits of increasing hydropower production, and determine the feasibility of new hydropower sites and the feasibility of adding hydroelectric units to existing dams. The national report, when complete, will be forwarded to Congress.

Since the study began in 1978, a preliminary inventory of hydropower projects was published in July 1979; a study assessing the demand for electricity and the need for hydropower has been completed; studies addressing several policy questions have been initiated; and through the use of a four-step screening process, thousands of existing and undeveloped projects have been analyzed to determine their physical potential, economic feasibility, and possible impacts. Furthermore, regional public meetings throughout the Nation were held during 1980 providing public information on the results in each regional study area. Draft regional reports have been coordinated with appropriate Federal, State, and local agencies. The national report is scheduled for completion in October 1981. In addition to providing a nationwide compendium of potential hydropower increases, it will outline institutional and policy considerations for hydropower development.

Tentative study findings for the Mid-Continent Area Reliability Council Agreement (MARCA) regional area indicate 48 hydropower sites including two undeveloped sites may have merit for hydropower development. MARCA includes the eastern one-fourth of Montana, the western one-half of Wisconsin, all of South Dakota except the Black Hills area, and all of the States of Nebraska, North Dakota, Minnesota, and Iowa (figure 1). If developed, the sites could increase existing hydropower capacity by 35 percent or 1,046 MW; new energy would amount to 1.7 million MWh within the MARCA region. This would help to meet 7 percent of the projected peak demand and 2 percent of the projected energy demand for the region during the period 1978 to 1990.

Tentative study findings indicate the potential new hydroelectric capacity for the Missouri River Basin is about 1,953 MW. Capacities may not agree with site specific studies performed by other agencies due to differences in methodology and assumptions in operation.

Sites identified in the Missouri River Basin are shown in table 12.

Bureau of Reclamation

Small Hydroelectric Development Study

The Bureau of Reclamation (BuRec) has recently completed an inventory of the potential for adding powerplants at existing facilities. The results of the inventory are summarized in the report entitled "Assessment of Small Hydroelectric Development at Existing Facilities, July 1980." (Water and Power Resources Service was renamed the Bureau of Reclamation in May 1981.)

Phase I of the Low-Head Hydroelectric Evaluation and Inventory was limited to investigation of potential power generating capabilities at existing project facilities. A low-head hydroelectric site is one which the water drops less than 20 meters or about 66 feet. This phase did not consider a maximum head limitation, and can be considered an evaluation of small hydroelectric opportunities since the study considered only small hydroelectric development—sites with less than a 15 MW plant capacity. Most larger capacity plants at projects have already been developed or are under study in the agency's ongoing planning program. More than 30 potential projects involving additions of hydroelectric power generation at existing facilities are under study at this time. Some of these projects were also included in this study. Sites being actively pursued for development by other entities were not considered although interest in some of the sites evaluated has been indicated by non-Federal entities.

The study assumes that reservoir operations and existing flow patterns required to supply other project purposes would not change. This reduces operational flexibility of a generating facility in meeting power system needs, however, such developments should be more acceptable from the environmental and social concerns standpoint. This premise was considered necessary because of legal and institutional constraints on reservoir operations and requirements for timely release of flows for other project purposes. Normally, electrical output from such proposed small hydroelectric development would not be firm energy but would only displace fuels used by thermal plants in the system. However, the coincidence of power production with system demands was considered; and, where appropriate, a firm energy value was assigned to the development since this would displace or delay development of other generating facilities in the system.

Table 12

MISSOURI RIVER BASIN POTENTIAL HYDROELECTRIC SITES
IDENTIFIED IN CORPS OF ENGINEERS
NATIONAL HYDROPOWER STUDY

STATE	PROJECT NAME	NAME OF STREAM	EXISTING CAPACITY (MW)	NEW POTENTIAL CAPACITY (MW)
CO	Horsetooth	Big Thompson	0	1.3
MT	Ruby Res.	Ruby R.	0	1.2
CO	Standley	Big Dry Cr.	0	3.1
CO	Tarryall	Tarryall Cr.	0	2.2
WY	Bull Lake	Bull Lake	0	3.2
CO	Button Rock	North St. Vrain	0	2.0
NE	Merrit Res.	Snake R.	0	2.0
WY	Gray Reef	North Platte R.	0	6.4
WY	Pilot Butte	Wind R.	0	5.0
MT	Fresno Res.	Milk R.	0	2.5
MO	Pomme De Terre	Pomme De Terre	0	3.6
WY	Boysen Res.	Wind R.	15	2.8
CO	Chatfield	South Platte	0	5.4
CO	Gross Dam	South Boulder	0	2.9
NE	Calamus	Calamus Res.	0	1.6
MT	Swift Res.	Birch Creek	0	4.3
CO	Cheesman	S. Platte R.	0	5.4
CO	Reservoir	Boulder Cr.	0	4.1
MT	Francis Lake	Offstream	0	6.8
KS	Milford Lake	Republican	0	7.8
MT	Clark Canyon	Beaverhead	0	3.0
MT	Broadwater	Missouri R.	0	5.5
MT	Hebgen Res.	Madison	0	7.0
WY	Guernsey	North Platte	4.8	17.4
KS	Tuttle Creek	Big Blue R.	0	21.6
MT	Hauser Lake	Missouri R.	17	18.8
MT	Black Eagle	Missouri R.	18	31.0
CO	Carter Lake	Big Thompson	0	23.6
WY	Seminoe Res.	North Platte	32	112.9
NE	Norden	Niobrara R.	0	21.9
WY	Glendo Res.	North Platte	24	56.4
WY	Pathfinder	North Platte	46	144.6
MT	Gibson Res.	Sun River	0	11.0
MT	Holter	Missouri R.	38.4	104.9
WY	Buffalo Bill	Shoshone R.	17	20.0
MT	Cochrane	Missouri R.	48	11.5
MT	Ryan	Missouri R.	60	44.9
MT	Morony	Missouri R.	45	52.0
MT	Tiber Res.	Marias R.	0	12.0
MT	Canyon Ferry	Missouri R.	50	90.0
MO	Bagnell Dam	Osage R.	172	130.0
MT	Lake Fort Peck	Missouri R.	165	185.0
MT	Yellowtail Afterbay	Bighorn R.	250	10.0
MT	Rainbow	Missouri R.	35	108.0
ND	Lake Sakakawea	Missouri R.	400	272.0
MT	Fort Benton	Missouri R.	0	362.7
KS	Kanapolis	Smoky Hill R.	0	2.2
		Total	1,437.2	1953.5

The report lists 56 sites in the 17 Western States for adding power which would produce greater benefits than their cost. Thirty-seven sites show no significant environmental or social impacts and, of these, 10 are identified within the Missouri River Basin. The Missouri basin sites of hydroelectric projects planned for future study are included in table 13.

Table 13

POTENTIAL HYDROELECTRIC PLANTS SLATED FOR STUDIES
MISSOURI RIVER BASIN

Plant	Size	Status
Merritt Dam--PSMBP, Ainsworth Unit	1,900 kw	FY 82 feasibility study also executive order encouraging private development
Granby Dam--Colorado Big Thompson	600 kw	FY 82 feasibility study also FERC application approved for study by private consultant
Pueblo Dam--Fryingpan-Arkansas Project	12,300 kw	FY 82 special study start
Guernsey Dam--North Platte Project	14,700 kw	FY 82 special study start
Sugarloaf Dam--Fryingpan-Arkansas Project	1,900 kw	FY 82 special study start
Carter Dam No. 1--Colorado Big Thompson Project	2,100 kw	Near infeasible
Horsetooth Dam--Colorado Big Thompson Project	2,400 kw	Near infeasible
Ruedi Dam--Fryingpan Arkansas Project	3,800 kw	FY 82 feasibility study, executive order encouraging private development
Seminoe--North Platte Project	500,000 kw	FY 82 feasibility study start
Alcova--Kendricks Project	500,000 kw	FY 82 feasibility study start

Solar-Wind Study

A potential wind energy project located near Medicine Bow, Wyoming, is under study. The project would have between 25 and 40 units generating between 2.5 MW to 4 MW each. Two units totaling 6.5 MW are scheduled to be installed and generating power by the end of 1981. A feasibility report on the 100 MW wind farm will be completed in 1981.

THE EFFECT OF UPSTREAM DEPLETIONS ON FUTURE MAIN STEM RESERVOIR HYDROPOWER PRODUCTION

A series of nine separate but related studies has been made by the Corps of Engineers to explore the regulation of Corps of Engineers main stem Missouri River reservoir projects. A primary purpose of these studies was to provide the Western Area Power Administration with data on the main stem reservoir system power production and peaking capability.

The studies examined various levels of water resource development in the Missouri River Basin. Each study has been identified with the appropriate development level and is based on the following conditions and objectives:

a. Historical streamflow, as obtained largely from USGS records, but utilizing Corps of Engineers estimates during some periods for which records are unavailable.

b. Streamflow depletions for the appropriate level of basin development as developed by the Work Group on Hydrologic Analysis and Projections of the Missouri Basin Interagency Committee in connection with the Missouri River Comprehensive Framework Study, (updated by the office of Upper Missouri Region, Bureau of Reclamation, in late 1979).

c. The loss of main stem reservoir storage by sedimentation appropriate to the examined development level.

d. Maintenance of downstream flows required for water supply, water quality control as established by Federal Water Pollution Control Act (FWPCA) as well as flows believed necessary for power-plant cooling and recreational purposes.

e. Maintenance of the highest navigation streamflow rates at downstream control points as practicable with the water supply available after satisfying the various depleting uses and providing equitable service to power.

f. Maintenance of release rates from each reservoir for maximum power generation consistent with the other stated purposes.

g. Maintenance of adequate storage space reserves in each reservoir to permit control of inflows to minimize damages during downstream flood situations.

Items considered in depletion estimates included irrigation, domestic use, industrial and municipal water use, thermal power, evaporation from reservoirs and ponds, livestock use, watershed treatment, and management of wetlands and fish and wildlife areas. During 1979, the Bureau of Reclamation reviewed previous estimates in detail and in this process made further detailed analyses of actual irrigation development during the 1929-1975 period for that portion of the Missouri River Basin controlled by the main stem reservoir system. Most recent analyses revealed that irrigation development since 1929 for the area as a whole has not been as great as was assumed during prior investigations. In fact, in the drainage areas controlled by Fort Peck and Garrison Reservoirs, it now appears that annual water use depletion from streamflow was less in 1975 than was occurring in the mid-1950's. Consequently, the Bureau of Reclamation developed new estimates of historical streamflow depletions for all of the Missouri River reaches above Gavins Point Dam for the 1929-1975 period, using the year 1975 as a base. Information from these studies relating to the hydropower function of the main stem system is summarized in table 14. Nameplate rating capacity of the main stem hydropower system is 2,098 MW.

Table 14

PROJECTED MISSOURI RIVER MAIN STEM RESERVOIR GENERATING CAPACITY
(Based on 1898-1979 Water Supply)

	Avg. Peaking Capability Megawatts				Average Generation			
					Summer	Winter	Annual (Jan-Dec)	
Study	Aug. Avg.	Dec. Avg.	Aug. 1933	Dec. 1933	Jun-Sep MW	Dec-Feb MW	MW	Million KW Hours
1-80-1975	2218	2193	2022	1940	1263	1010	1124	9860
1-80-1980	2211	2190	2002	1929	1254	989	1114	9772
1-80-1985	2203	2183	1979	1912	1229	978	1098	9632
1-80-1990	2195	2173	1951	1924	1203	954	1077	9447
1-80-1995	2204	2186	1919	1920	1172	912	1045	9166
1-80-2000	2190	2173	1876	1922	1132	882	1012	8880
1-80-2020	2164	2159	1764	1894	1052	802	937	8216
1-80-2040	2124	2132	1662	1783	984	708	854	7493
1-80-2060	2108	2131	1859	1923	945	652	805	7059

Source: Corps of Engineers, Missouri River Division, Reservoir Control Center Studies Series 1-80.

The record period used for obtaining averages was the complete 1898-1979 period including the drought period of the 1930's. Analyses conclude that the 1930's drought was unusually severe and can be expected to recur much less frequently than would be expected from the period of record available. Since the major effects of this drought upon system regulation occur during the 1934-1942 period, average values that would more nearly represent those that would occur under normal conditions (normal being defined as a period when extremely severe droughts did not occur) would be averages with the 1934-1942 period eliminated. Table 15 presents such data.

Table 15

PROJECTED MISSOURI RIVER MAIN STEM RESERVOIR GENERATING CAPACITY
(Based on 1898-1933 and 1943-1979 Water Supply

Study	Average Peaking Capability Megawatts Aug.	Dec.	Average Generation Summer Jun-Sep MW	Winter Dec-Feb MW	Annual MW	(Jan-Dec) Million KW Hours
1-80-1975	2281	2251	1328	1082	1187	10,408
1-80-1980	2277	2247	1321	1062	1178	10,333
1-80-1985	2273	2239	1300	1045	1162	10,194
1-80-1990	2265	2230	1274	1020	1141	10,008
1-80-1995	2270	2238	1248	976	1110	9,734
1-80-2000	2255	2225	1206	943	1076	9,436
1-80-2020	2219	2206	1127	857	1001	8,775
1-80-2040	2175	2175	1063	758	918	8,051
1-80-2060	2149	2167	1024	695	867	7,607

Source: Corps of Engineers, Missouri River Division, Reservoir Control Center Studies, Series 1-80

Chapter 3

ENVIRONMENTAL ISSUES ASSOCIATED WITH ELECTRICITY GENERATION

The economic impacts of continued reliance upon unstable supplies of foreign imported oil have spurred the United States to look at a national energy plan. Legislation in the form of the Fuel Use Act of 1979, the Windfall Profits Tax Act of 1980, and the Energy Security Act of 1980 provide the impetus for decreasing reliance on imported oil. President Carter's July 1979 energy message also communicated a sense of urgency to the commitment of the U.S. to become energy self-sufficient. Energy self-sufficiency is expected to come about through strong national energy conservation programs, conversions of oil- and gas-fired power plants to coal, development of a coal-based synthetic fuels industry, and total reliance on coal and uranium as a fuel source for all new electric power plants.

This reliance and emphasis on vigorous expansion of domestic coal, uranium, oil, and gas production means significant development activity in the Missouri River Basin States. The availability of near-surface, thick deposits of coal in the basin States provides an attractive resource for development. Projections show coal extraction and power production will double within the next five to eight years. This increase in coal mining and power plant operation translates into more air emissions, increased water usage, more land disturbance, and more people. This chapter discusses the environmental aspects of these factors.

In addition to coal, the Missouri River Basin contains economically recoverable quantities of natural gas, petroleum, and uranium. Development of solar and wind resource potential in the basin could have significance as nonpolluting energy sources in the future. There is limited potential for additional hydroelectric power development in the Missouri River Basin. The crucial role will be in the supply of water for development of the basin's other energy resources.

Intensive efforts to develop the energy resource potential of the basin, particularly in the northern Great Plains, have generated considerable controversy regarding the possible environmental and social consequences of such developments. The nature of the social and environmental concerns is diverse. Such concerns include the possible adverse effects of development on the social structure of local communities, crime rates, costs associated with waste water treatment facilities, adequacy of facilities, school systems, air quality deterioration, water depletion, decrease in agricultural production capabilities, effectiveness of reclamation measures, postdevelopment economies, and ecological values. In response to these concerns, numerous studies have been initiated by industry, universities, the scientific community, and government to more clearly define the impacts that can be anticipated from an accelerated level of energy development activity.

ENVIRONMENTAL IMPACTS

Coal

Mining and Extraction

Air Quality. Air quality deterioration associated with coal resource development in the Missouri River Basin may be expected with future increases in coal production. The primary air quality impact of coal mining operations is the potential for an

increase in suspended particulates, resulting from fugitive dust emissions. Surrounding concentrations of particulate matter can be expected to increase on at least a localized basis, particularly in areas where there are many coal mines. This situation is particularly important in northeastern Wyoming, southeastern Montana, and central North Dakota.

Studies are under way to determine the magnitude of particulate emissions from coal mines in an effort to obtain more accurate estimates of coal mining impacts. Models and other analytical techniques are also being utilized to project various air impacts of particulate additions. Emission control technologies for coal mining and coal conversion operations are being developed and implemented. Several of the basin States require coal mines to acquire air permits prior to operation and also to monitor the mining area.

Water Quality. The surface mining and extraction of subbituminous coal and lignite in the Missouri River Basin has the potential for adversely affecting the quality of the waters of the basin. Some of the more significant potential impacts include the deterioration of surface water quality due to increased sediment loads, channel modifications, change in stream gradient, coal mine leachate, and the disturbance and contamination of shallow ground water systems, including multi-aquifer interconnection and aquifer disruption.

The magnitude and duration of such environmental impacts is primarily a function of the mining and reclamation practices undertaken by the operator; reclamation laws, practices that must be implemented by the operator as mitigating measures include premining planning; selection of surface mining methods and coal extraction and preparation practices which maximize stabilization and minimize soil erosion; utilization of mined land reclamation methods which include selective spoil placement, runoff interception and diversion, topsoiling, grading and revegetation; water-quality monitoring; preservation of the hydrologic balance; and protection of alluvial valley systems.

Current studies by the industry and government relating to the environmental effects of surface mining and extraction of energy resources in the Missouri River Basin have been oriented toward the determination of baseline environmental conditions in future development areas, the evaluation of environmental impacts resulting from existing mining operations, and the utilization of models or other analytical techniques to project water impacts and reclamation potential. Such studies are currently being undertaken by the Environmental Protection Agency, U.S. Geological Survey, Bureau of Land Management, Bureau of Reclamation, Bureau of Mines, Agricultural Research Service, U.S. Forest Service, and numerous State agencies.

Coal Conversion/Combustion

Air Quality. Stack emissions of concern from coal fired power plants consist principally of particulates, sulfur dioxide, nitrogen oxides, and certain other trace heavy metals. These pollutants can be limited or controlled by using a clean fuel or removing a significant amount of the pollutant from the stack gases. A number of facilities that all contribute their share of pollutants to the atmosphere will gradually increase the impact of those pollutants on the environment until no more can be tolerated, especially in a small area. Resource availability often dictates the location of such facilities, and the competition for space to develop is keen.

The combination of air emissions from power plants with the emissions from other industrial activity including synthetic fuels production, mining, oil and gas operations, etc., along with emissions resulting from increased population growth, represents the major air quality issue. Existing laws and regulations are available to ensure that individual facilities do not create significant environmental degradation. However, although the authority to ensure regional compliance with air quality goals exists, the analytical tools, i.e., modeling and monitoring, may not be adequate to ensure compliance.

Control technology exists to allow new power plants to effectively limit emissions. Stringent regulations also exist that govern coal combustion facility activities.

EPA has issued New Source Performance Standards for fossil-fuel-fired power plants (40 CFR 60). These performance standards require very stringent control, i.e., better than 99 percent, of particulate matter; significant reductions, i.e., 20 to 90 percent, of sulfur dioxide; and properly designed boilers to minimize nitrogen oxide emissions.

The Clean Air Act Amendments of 1977 (Public Law 95-95), enacted August 7, 1977, made certain changes to the Environmental Protection Agency's regulations concerning the prevention of significant deterioration of air quality. Recent court decisions further refined these requirements. The final regulations are found in the August 7, 1980, Federal Register and codified in 40 CFR 52-21. These regulations establish a scheme for protecting areas with air quality cleaner than minimum national ambient air quality standards. Section 162(a) of the Act automatically classifies all international parks, all national wilderness areas which exceed 5,000 acres in size, all national memorial parks which exceed 5,000 acres in size, and all national parks which exceed 6,000 acres in size as class I areas. This designation applies only to areas which were in existence on the date of enactment of the new amendments. The Federal Register, (Volume 42, No. 212, dated Thursday, November 3, 1977) identified those Federal lands which are mandatory class I areas. Table 16 lists mandatory class I areas within the Missouri River Basin with total acreage shown for each area, some portion of which may be outside of the basin.

Table 16

FEDERAL LANDS - CLASS I AREAS

National Parks over 6,000 acres	Total Acres
Colorado - Rocky Mountain	263,138
Montana - Glacier	1,012,599
South Dakota - Wind Cave	28,060
Wyoming - Yellowstone	2,219,737
National Wilderness Areas over 5,000 acres	**Total Acres**
Colorado - Rawah	26,674
Montana - Bob Marshall	950,000
- Gates of the Mountain	28,562
- Medicine Lake	11,366
- Scapegoat	239,295
North Dakota - Lostwood	5,577
South Dakota - Badlands	64,250
Wyoming - Fitzpatrick	191,103
- North Absaroka	351,104
- Teton	557,311
- Washakie	686,584
National Memorial Parks	
North Dakota - Theodore Roosevelt National Memorial Park	69,675

Only very small amounts of air quality degradation may occur in class I areas. The remainder of the United States (other than National Parks and Wilderness areas) is categorized as class II. The incremental air quality degradation allowed in these areas is designed to allow moderate industrial growth. Under PSD (prevention-of-significant-deterioration) regulations, certain governmental entities and jurisdictions (i.e., Indian tribes, county governments) have the power to select the level of increments (i.e., from very small to allowing degradation up to national air quality standards) that they desire. The Northern Cheyenne Indian Reservation has been designated a class I area by the tribe. Governmental entities may also reclassify areas from class II to class III. This doubles the amount of air quality deterioration which may be allowed. Since pollution ignores political boundaries, the siting of various stationary facilities will be critical to ensure that assigned portions of incremental pollution deterioration are not exceeded or overused.

Water Quality. Coal conversion includes combustion, gasification, and liquefaction and can result in water quality and quantity problems. The quantity and quality of water effluents are dependent upon considerations such as the type of process, type of intermediate and end products, pollution control measures, and site-specific factors, among others.

Since no commercial size coal gasification or liquefaction facilities have yet been built in the United States, present quantification and qualification of wastes from such facilities are generally based upon extrapolations from laboratory experiments, bench scale tests, and limited pilot plant operations. Some information has, however, been gained from commercial size operations outside the United States.

On an individual plant basis, the surface water quality impact of coal conversion in the Missouri River Basin may be low if facilities continue to pursue a no-discharge policy. Surface water quality impacts could result, however, due to cumulative impacts of depletion resulting from construction and operation of several coal conversion facilities. Cumulative impacts stemming from water depletion may be offset somewhat by practicing water use minimization. Minimization can be achieved through reuse and conservation in cooling water requirements. Reduction or control in those instances may be achieved through combined wet/dry or all dry cooling. EPA Region VIII and the Colorado River Salinity Control Forum have both adopted policies to promote the use of low quality water for industrial purposes. The use of highly saline or otherwise contaminated water for process cooling requirements provides for the continued availability of good quality water for municipal and domestic uses. In those instances where once-through cooling is practiced, thermal problems could result. Assessments of impacts on streams must be performed by the utility pursuant to section 316 of the Clean Water Act prior to approval of a once-through system.

Ground water may be significantly impacted unless adequate facility planning and maintenance of total retention facilities, proposed deep well injection systems, dewatering of in-situ operations, and backflood water controls are followed. Design, construction, and maintenance of total retention facilities must ensure that contaminated wastewater is totally contained and that proposed deep well injection systems will not introduce wastewater into presently utilized or future source of drinking water aquifers. Dewatering could, depending upon quality, result in potential surface water problems associated with disposal. Backflood waters could have a major impact on the ground water system due to water quality changes. The quality of backflood waters will have to be characterized, and plans will have to be developed to prevent such backflooding or to improve the quality of the backflood waters. Implementation of State and Federal requirements through the Underground Injection Control Program (40 CFR 122 and 146) will provide mitigation measures.

Solid wastes associated with coal conversion include: process waste residues and nonmarketable byproducts, spent catalysts if not regenerable, solid wastes from pollution control processes and incoming water treatment, and supporting facility wastes such as sewage sludge and waste products from construction and maintenance. Adverse environmental impacts of landfill stability, leachate formation and movement, and reclamation can result if proper solid waste techniques are not planned and pursued. Implementation of State and Federal requirements pursuant to the solid and hazardous waste regulations (40 CFR 260) should minimize these impacts.

Transportation, Transmission, and Support Facilities

Whether talking about raw coal or the products of conversion such as gas, oil, or electrical energy, the resource or product must be delivered to the user. Coal, as a raw resource, can be transported by truck, rail, barge, or slurry pipeline.

Similar to the major issue of extraction and conversion of coal, the principal issue of transportation involves regional impacts. Proper planning to ensure

maximum use of existing corridors and optimizing use of new corridors is the key factor to mitigation of adverse impacts. Transportation of coal resources will pose some fugitive particulate emission problems along the route selected. The frequency of the trips, season, and control techniques employed will all determine the magnitude of the problem. As the coal industry grows, the transportation system will expand to handle the increased volume of coal produced.

Support facilities include the construction and maintenance of an energy facility but, possibly more important over the long term, are the existing and new communities that will house and supply the personnel required to support these facilities. Many factors about "boom" growth and the resultant effect on the environment remain unknown, but the visual and measured effect on the air quality in high-growth communities associated with energy development have been documented. Proper planning and guidance of growth in the affected communities will be necessary in order to avoid or minimize the impacts caused by an influx of many people.

Potential environmental impacts to surface and ground waters that are common to all transportation modes include runoff from storage and load-out facilities and accidental spills. Runoff from haul roads and rail rights-of-way, where natural materials and chemicals used for dust control and weed control can be transported, have potential for impact on water quality. If black water from slurry pipelines is not properly reused, contained, or treated and released, impacts to water quality can result. Water supply reductions and competitive water use for slurry pipelines can also impact water quality through depletion.

Coal transportation, particularly by truck and rail, can also produce significant problems associated with community traffic flow disruption and noise. As coal transportation increases, the potential for disruption also increases and may pose a problem.

Synthetic coal conversion products (gas and oil) can be transported by truck, rail, barge, or pipeline. Potential impacts from transporting by such modes are similar to transporting coal in the same manner. If pipelines are properly constructed and maintained, water impacts can be minimized. Accidental spills, however, can have a significant impact on water quality.

Transmission of electric power can impact water quality through runoff from improperly maintained transmission rights-of-way. The potential does exist for health and nuisance effects from high voltage lines, but such impacts can be minimized by careful route and structure planning.

Land Use and Reclamation

Perhaps second only to regional concerns over social, cultural, and economic changes brought about by large-scale industrialization, principally related to the extraction and the use of energy fuels, is a concern for the long-term successful reclamation of lands containing shallow deposits of coal and uranium that have been or will be mined by surface extraction methods. The reclaiming of mined or orphaned (abandoned) land cannot be overemphasized because it is critical to assuring that surface mining represents only a temporary use of the land.

In view of the wealth of experience gained in revegetating agricultural lands and lands disturbed during highway construction and urban building, it is useful to

question the differences, if any, between agricultural or highway reclamation and reclamation of mined lands. Generally, a significant difference is the thickness (or depth) of earth materials disturbed during surface mining, and the fact that, in many cases, materials lying over the coal (or overburden) are by their geologic nature inherently saline (by virtue of high sodium content in addition to other minerals). Obviously, such high sodic materials, unless properly placed, could seriously impair farming.

Inhabitants of the Upper Missouri River Basin are only too familiar with the problems of wind and water erosion of lands from which vegetation has been removed. Similarly, surface mined lands will be subject to such erosive forces until a permanent protective vegetative cover is established. Basin residents are also aware of the difficulties of attempting to reintroduce native plants to disturbed lands. Other challenges encountered when reclaiming mined lands involve slope and aspect of graded lands. Although there is certainly promise for success in select areas, many years will be required to determine whether revegetation efforts on surface mined lands will truly be successful in terms of plant stability, succession, and productivity.

There is concern over the relative importance of land disturbance caused by surface mining. Actually, those lands with deposits of coal at least 5 feet (1.5 meters) thick and lying less than 200 feet (60 meters) below the surface which may presently be considered economically recoverable occupy a very small percentage of the total area of the Missouri River Basin. However, overburden above such coals is often thinnest in valleys and the lower plains. Therefore, it is most economical to mine those coals. These same valleys and plains are often the mainstays of the agricultural operations—operations which in turn form the economic backbone of the basin and which will continue to persist over the longer term. Thus, the lands that may be disturbed by surface mining of coal tend to include, in a number of cases, lands currently used for more intensive agriculture—as opposed to lands in the areas of higher elevation with rocky outcrops and lower agricultural productivity. Surface mined land reclamation has not demonstrated, to date, that the essential agricultural and hydrologic functions of such valley areas can always be reestablished.

Petroleum and Natural Gas

The four major phases of the petroleum and natural gas industry are exploration, production, transportation, and processing. Each phase of the industry has varying environmental impacts in varying degrees. The exploration phase causes only minor environmental impact in the form of land disturbance to create access roads and drilling areas, solid waste disposal in the form of drill cuttings, potential dust generation from land clearing, brine seepage from holding ponds, and perhaps noise impacts.

Environmental impacts resulting from the production of oil are somewhat related to the type of recovery (primary, secondary, and tertiary) being practiced. The advanced recovery techniques require more energy inputs and more water resulting in increased potential of air emissions and water pollutants. The primary air pollutants of concern are hydrocarbons from evaporation and hydrogen sulfide and sulphur dioxide from flaring. Oil and grease, salts, phenols, and total dissolved solids must be considered when discussing environmental impacts from water reinjection or discharge.

The transportation phase of the industry places stress upon the environment in the form of land disturbance during pipeline construction and in the form of potential oil spills during the operation of the pipeline. Depending on location, oil spills can cause environmental degradation of land and water.

Section 311 of the Federal Water Pollution Control Act of 1972 (P.L. 92-500) has declared that it is the policy of the United States that there should be no discharges of oil into navigable waters. The EPA has been delegated the authority to remove oil spills in water if the owner or operator of the vessel or facility causing the discharge is not performing proper removal.

Effects of oil in water have been dramatically displayed in numerous recent spills. Most visible is the coating effect oil has on almost anything it contacts—wildlife, waterfowl, vegetation, and fish. The oil film acts as a barrier to normal fluid and air interchange between any organism and its supporting environment. Distress, and in most instances death, will befall the affected organism. A major oil spill recorded in the Missouri River Basin in 1980 was a result of a pipeline break in Wyoming. Oil entered the North Platte River.

Oil spills can be grouped into two main categories to aid in identification: transportation-related and nontransportation-related. Transportation related spills occur from accidents when the oil is being moved by pipeline, railroad, truck, or boat. Nontransportation-related spills occur from fixed storage vessels, refineries, and production fields. It is not anticipated that new refineries will be built in this area, and there are no significant producing fields downstream from Williston, North Dakota. However, there will be an increase in bulk oil storage at the energy development sites. A spill prevention, control, and countermeasure plan, developed by the owner or operator to comply with 40 CFR 112 should minimize the potential for any spills from reaching a waterway.

The processing phase of the industry has probably the greatest environmental impact. Refining of the crude oil into marketable products requires water use, generates air emissions, and produces solids to be eliminated. Environmental control regulations in the form of water effluent guidelines and new source performance standards for air quality are being issued to minimize the environmental impact of new or modified refineries.

Although oil production in the basin States is expected to remain relatively constant, natural gas production is expected to increase significantly. Major gas discoveries in the Williston Basin (North Dakota) and in the Overthrust Belt (Montana) have created a promising resource potential. Environmental impacts from this gas production center primarily on air emissions. Since the gas is extremely sour, sulfur recovery facilities must be constructed along with the gas processing facility. Residual sulfur dioxide and hydrogen sulfide emissions may be in large enough quantity from a single plant or from a combination of facilities in the same general proximity to create an environmental concern.

Vast reserves of tight sands gas exist in Montana and Wyoming. If the decontrolled price of gas reaches an economically favorable level for this resource to be developed, environmental impacts must be considered. Air emissions similar to those for conventional gas production must be controlled. Potential ground water quality and flow impacts due to fracturing and subsidence must be considered.

Nuclear Fuels Extraction and Power Generation

Due to the limited number of nuclear facilities in the Missouri River Basin, the possibility of a nuclear catastrophe associated with these plants is somewhat remote. The more realistic environmental problems in basin States will come from mining activities.

Potential radioactivity problems are not restricted to plant operations. In Wyoming, a State that contains 35 percent of the total U.S. uranium reserves, extensive uranium resource development could greatly increase the potential for radioactive contamination. Due to possible impacts on surface and ground water resources, uranium mining and milling must be carefully monitored.

Additional problems relate to the presence of radon gas, the infiltration of radium into ground waters, and reclamation of mined areas.

Alternative Energy Resources

Solar Energy

In examining the solar resource potential, it is advantageous to divide solar technology applications into two categories. These are local or individual technologies (e.g., solar home heating, crop drying, greenhouses) and community or regional technologies, (e.g., solar power plants). The indication has been that solar energy is one source of energy that will not degrade the environment. Such a statement may very well be true when the solar resource is compared to conventional energy sources such as coal. Solar energy, however, does exhibit some subtle environmental impacts. For example, the question of esthetic impact arises with respect to local technologies. The design of solar heated buildings is significantly different from that of conventional buildings. This is necessary in order to maximize collection and use of the solar energy that strikes the collector surface.

Regarding community technologies, it is essential to make the most beneficial and appropriate use of lands. This is particularly relevant since a 1,000 MW commercial solar power plant, such as is now envisioned, would require 3,000 to 6,000 acres (4.7 to 9.4 square miles) of land.

Wind Energy

Much of the region encompassed by the Missouri River Basin provides great promise as an area within which large-scale wind energy development may occur. Sites such as Great Falls, Montana, and Casper, Wyoming, record average wind speeds in excess of 13 miles per hour. The environmental impacts associated with wind energy development appear to be relatively insignificant. Where there are clusters of wind turbines, there is the possibility of localized weather disturbances but perhaps no more so than that which is prevalent around tall buildings. There is also the possibility of noise pollution resulting from the revolving blades and the undesirable esthetic impact of turbine towers cluttering the landscape. However, it is felt that the net benefits of the replacement of a fossil-fuel-derived energy source far outweigh the negative aspects. A large scale wind utilization program is being demonstrated near Medicine Bow, Wyoming.

Geothermal Energy

Although large-scale geothermal resource development seems relatively remote within the Missouri River Basin, both "known geothermal resource areas" and "lands

valuable prospectively for geothermal resources," as defined by U.S. Geological Survey, do exist in basin States. The geothermal resource exhibits a greater and more diverse number of environmental impacts than those associated with alternative energy sources. Air emissions that contain pollutants, such as particulates, sulphur oxide, nitric oxide, carbon monoxide, and hydrogen sulfide, are critical. Degradation of surface and ground waters may also occur unless the geothermal effluent is disposed of properly. Proper disposal involves injection of the effluent into the geothermal zone. This would be done not only to reduce deterioration of potable water sources but also to prevent subsidence due to aquifer mining. Injection must also be performed to ensure that seismic activity is not induced along fault zones.

Monitoring systems for geothermal fields are being developed by EPA's Environmental Monitoring and Support Laboratory in Las Vegas, Nevada.

Biomass

Biomass energy is produced as a result of the use of organic material, either directly or through chemical conversion, as a fuel. Sources of biomass are fast growing trees or other vegetative types that may be burned directly, animal wastes that are converted to methane, and starch grains that are converted to methanol which is then combined with gasoline. Environmental impacts associated with energy production from biomass include air emissions from conversion facilities and disposal of wastes from completed processes. Again, the question is whether it is better to use agriculturally productive lands to produce fuel or food.

Solid Waste

Solid waste (garbage or trash) represents yet another source of energy. However, since there are few metropolitan areas within the Missouri River Basin compared to other regions of the country, the use of solid waste as a supplemental fuel may not be practical until some time in the future. The Denver Council of Governments, in a study partially funded by the Environmental Protection Agency, has found that a resource recovery plant that would convert solid waste to fuel pellets is not feasible at this time. Other resource recovery projects are investigating the use of wood waste as an energy source.

Environmental impacts prevalent when solid waste is converted to fuel include air emissions, particularly if exotic elements used in packaging are emitted. Further, there is still the necessity to dispose of ash or waste following the conversion process.

SOCIOECONOMIC-CULTURAL-ESTHETIC IMPACTS

The major socioeconomic impacts related to semi-intensive and concentrated energy development activities in the Middle and Upper portions of the Missouri River Basin are: (1) immigration to meet increased employment demands during construction and operation phases of development; (2) the resultant demand for housing and human and municipal services, coupled with community problems associated with obtaining or generating front end monies to provide traditional community services; (3) the impacts on the local and regional economy of new and increased employment opportunities at higher wage scales, new revenues produced by energy activities, and changes in the structure of the economy as a result of shifts in the relative importance of the basic economic sector; and (4) impacts associated with the postdevelopment period.

Most of the communities that have been or will be impacted by energy development are small rural communities. Residents place a high value on a rural life style that has evolved over several decades, with particular importance placed on those values that distinquish small rural communities from urban areas.

A primary concern expressed by residents of rural communities is the potential for these communities to become "boom towns" with the local residents having limited control over many aspects of growth-related problems. Planning is necessary to mitigate adverse impacts. The primary problem is one of the community obtaining, in a timely fashion, the answers to when and where and how many people will be associated with a particular development initiative or mix of developments. In order to mitigate the "boom town" effect and to obtain the needed answers about development, a process involving Federal, State, local government, and industry participation and coordination has evolved. This process, the Impact Team concept, combines information and assistance available from Federal and State programs, both technical and financial, with local funding capabilities and industry participation. The Impact Team meets regularly to assist the affected community and area in defining and prioritizing needs and determining methods for obtaining or financing these needs.

Various government sponsored publications such as the Missouri River Basin Commission/USGS Resource and Land Investigations Program, Western Coal Planning Assistance Project Planning Reference System and the Environmental Protection Agency's Action Handbook are available to assist local decisionmakers and planners in gaining control over growth-related problems.

Visual impacts associated with various types of development could cause significant changes on relatively unscathed landscapes. In addition to community related considerations, projected visual impacts would include those associated with road and facility impacts, water quality impacts, and general deterioration of environmental quality. The magnitude of eventual impact is, of course, very much a function of the adequacy of the environmental controls and mitigation measures planned prior to development.

The added demands on the recreation resource base caused by increased population levels could contribute significantly to environmental degradation if a wide disparity between supply and demands exists. A main concern is the overuse and exploitation of existing resources because funding priorities for recreation facilities and opportunities are often based on existing population levels rather than projected levels of demands.

To some extent, there is concern among local residents that newcomers to their community might not have the same appreciation for protection of the natural resources base. Problems associated with poaching of game animals and law enforcement are some of the concerns expressed by predevelopment residents.

GENERAL ENVIRONMENTAL REGULATIONS

Federal environmental regulations that pertain to most aspects of energy production have been issued and are enforced principally by the Department of the Interior and the Environmental Protection Agency. These Federal regulatory programs all have the goal of delegation of responsibility to the appropriate State agency. These regulations have direct implications for fuel mining and processing areas, as well as for generating facilities.

Environmental Protection Agency

The Environmental Protection Agency is responsible for administering four major water quality regulatory programs related to energy development and electric power production and participates in two other programs.

- National Pollutant Discharge Elimination System Program (NPDES): Any potential discharge to a navigable surface stream must be covered by a NPDES permit. NPDES permit limitations are established using guidelines available such as those discussed below. South Dakota is the only Missouri River Basin State in which EPA administers the permit program. The Clean Water Act of 1977 established the goal of no discharge of pollutants into navigable streams by 1983.

- Coal Mining Point Source Effluent Guidelines: These regulations establish maximum discharge concentrations for hydrogen ion concentrations, iron, manganese, and total suspended solids for coal mine point source discharges. Final rules which define Best Practicable Treatment technology applicable to existing sources became fully effective on July 1, 1977 (40 CFR 434). Regulations defining Best Available Treatment technology for new sources were recently promulgated (12/80).

- Ore Mining and Processing Point Source Effluent Guidelines: These regulations established maximum allowable discharge limitations for cadmium, zinc, arsenic, radium 226, uranium, chemical oxygen demand, total suspended solids and hydrogen ion concentration for uranium mines and mill point source discharges. The regulations were recently promulgated (12/80).

- Underground Injection Control Program: Under regulations authorized by the Safe Drinking Water Act (Public Law 93-523), States are encouraged to establish programs that require issuance of a permit for the underground injection of all wastes and that prohibit injections under circumstances that would endanger drinking water sources.

- Thermal Effluent Limitations: Section 316 of the Federal Water Pollution Control Act required EPA to develop guidelines for the control of thermal discharges. As a result, effluent guidelines and standards were developed and published for steam-electric power generating point sources in 1974. In response to legal challenges, the existing guidelines were remanded by court order in July 1976. EPA revised the guidelines to comply with the court finding. Final rules were issued in 1979.

- 404 Program: Under Section 404 of the Clean Water Act, EPA and the Army Corps of Engineers participate in the permitting of any activities which involve dredging and filling in navigable streams. A permit must be obtained from the Corps. EPA's role is review and concurrence.

Department of the Interior

The U.S. Department of the Interior administers two major coal resource regulatory programs. These include the new Federal Coal Management Program and the Surface Mining Control and Reclamation Act.

- Federal Coal Management Program: A program to resume leasing of Federal coal was implemented in 1979. Regional coal teams (RCT) have been established in order to define leasing goals and to prepare specific tract delineations. Three RCT's are operative in the Missouri River Basin States--the Fort Union (North Dakota and Montana), the Powder River Basin (Wyoming and Montana), and the Green River Hams Fork (Colorado and Wyoming). The first lease sale is scheduled for 1981.

- Surface Mining Control and Reclamation Act of 1977: This act (Public Law 95-87), signed into law on October 3, 1977, creates an Office of Surface Mining Reclamation and Enforcement within the Department of the Interior. The law establishes minimum environmental protection standards for the mining of all coals. Specific duties of the office under the law, include administering the act's regulatory and reclamation programs, providing grants and technical assistance to the States, and approving and disapproving State programs. The act also includes provisions that specify inspection and enforcement requirements, create an abandoned mine reclamation fund, and provide for surface owner protection. The act emphasizes State administration of the program. Regulations implementing the Permanent Program were issued March 13, 1979 (30 CFR 700 and 800). Two major court decisions have remanded a certain portion of these regulations.

In addition to its major regulatory programs, the Department of the Interior requires that environmental impact statements be prepared by utilities filing power plant applications. On July 25, 1977, the Department of the Interior announced the availability of a new contract-prepared report entitled "Guidelines for the Preparation of Environmental Reports for Fossil-Fueled Steam-Electric Generating Stations." The report is intended to be used in developing future departmental guidelines for environmental information required from power plant permit applicants.

Also within the Department, the U.S. Fish and Wildlife Service gets involved in most energy resource and water resource development projects through their responsibilities to protect rare and endangered species, the values of the Park System via their Organic Act and the Clean Air Act Amendments of 1977.

Chapter 4

LAWS, POLICIES AND REGULATIONS AFFECTING ENERGY DEVELOPMENT

The 1977 Status of Electric Power Report provided a summary of laws and policies pertaining to the production of electrical energy. Since that report was published, both the Federal Government and the individual States have addressed energy development through additional laws and regulation. Some of the more important laws, policies, and regulations that have been instituted since the November 1977 report are discussed in this chapter.

FEDERAL

95th Congress

Congress passed the National Energy Act on October 15, 1978, after nearly a year-and-a-half of deliberation. The purpose of the act was to decrease oil imports by replacing oil and gas with abundant domestic fuels in industry and electric utilties, to reduce energy demand through improved efficiency, to increase production of conventional sources of domestic energy through more rational pricing policies, and to build a base for development of solar and renewable energy sources. The act is composed of five bills:

The National Energy Conservation Policy Act of 1978,
The Powerplant and Industrial Fuel Use Act of 1978,
The Public Utilities Regulatory Policies Act,
The Natural Gas Policy Act of 1978, and
The Energy Tax Act of 1978.

National Energy Conservation Policy Act of 1978

The National Energy Conservation Policy Act was signed into law on November 9, 1978 (Public Law 95-619). The purpose of the act was to provide for the regulation of interstate commerce, to reduce growth in demand for energy in the United States, and to conserve nonrenewable energy resources produced in the Nation and elsewhere without inhibiting beneficial economic growth.

A portion of the act directed toward residential energy conservation established a program requiring utilities to offer energy audits to their residential customers. The audits would identify appropriate energy conservation and solar energy measures and estimate customers' likely costs and savings. Utilities also are required to offer to arrange for the installation and financing of any such measures. This act, extended through 1980, the Department of Energy weatherization grants program for insulating lower income homes as well as provided a solar energy loan program administered by HUD to support homeowners and builders to purchase and install solar heating and cooling equipment in residential units.

This act also set up an energy conservation program for schools, hospitals, and buildings owned by local governments to include energy audits.

Other provisions of the act established energy efficiency limits on certain products and processes including automobiles and invoked civil penalties relating to automobile fuel efficiencies and Federal energy initiatives.

Power Plant and Industrial Fuel Use Act of 1978

This act is intended to reduce the importation of petroleum and to increase the national capability to use indigenous energy resources and to further national energy self-sufficiency. The act also intends to conserve natural gas and petroleum for uses other than generation of electricity and to encourage greater use of coal and other attendant fuels in lieu of national gas and petroleum as a premium energy source.

The act prohibits use of natural gas or petroleum as a primary energy source in any new power plant and requires new power plants to use coal or other fuels as primary energy sources. Provision is made for the establishment of a loan program to assist utilities to raise necessary funds for pollution control.

Finally, the act provides financial assistance to areas impacts by increased coal or uranium production.

Public Utility Regulatory Policies Act of 1978

This act instituted programs to provide increased conservation of electric energy, increased efficiency of use of the facilities and resources by electric utilities and equitable retail rates for electric customers. In addition, it established programs to improve wholesale distribution of electric energy by Federal agencies to encourage expeditious development of needed additional hydroelectric potential at existing small dams. Also, other programs called for the conservation of natural gas, while insuring equitable rates and encourage development of crude oil transportation systems.

Titles I and III of the act pertain to the retail regulatory policies for electric and natural gas utilities and title II pertains to Federal Energy Regulatory Commission and Department of Energy authorities. In addition, title II encourages establishment of favorable industrial cogeneration facilities, requiring utilities to buy or sell power from qualified cogeneraters at reasonable rates.

Title IV establishes a loan program for small hydroelectric power projects to aid in their development and simplified the licensing procedures to expedite development of these projects. This title has received substantial attention in the individual States as well as from the Department of Energy.

Other titles of the bill included provisions for development of crude oil transportation systems and contained procedures to expedite issuance of permits and for enforcement of rights-of-way. Other provisions called for: (1) additional funding for the research institutes, (2) establishment of three additional university coal research laboratories, (3) rules for the conversion of natural gas uses to heavy fuels, emergency conversion fuel use by utilities and other facilities during natural gas emergencies, (4) natural gas transportation policies, and (5) rules for the utilization of conserved natural gas.

Natural Gas Policy Act of 1978

The Natural Gas Policy Act sets a series of maximum lawful prices for various categories of natural gas, including gas sold in both interstate and intrastate

markets. The intent is to eliminate regulatory distinctions which has existed between the two markets and to deregulate certain gas prices. Price controls on new gas, and certain interstate gas are to be lifted as of January 1, 1985, and high-cost gas, was to be deregulated approximately one year after enactment.

The act gave emergency authority to the President if a gas shortage were to exist and established so-called high priority uses for residential or small commercial establishments or any use which would endanger life, health, and maintenance of physical property. It also provided that the interstate gas supply needed for certain agricultural and industrial uses would not be curtailed unless it was needed to serve high priority uses.

Energy Tax Act of 1978

Title I of this act provided a nonrefundable income tax credit for installing residential insulation and for energy conservation measures up to $300 or 15 percent of the first $2,000 expended. Also, a residential solar tax credit was established for residential insulation and solar or wind equipment up to a maximum credit limit of $2,200.

Title II included a "gas guzzlers tax," which was a graduated excise tax on cars that fall substantially below federally mandated one fleet-wide mileage standards. It also provided exemptions of motor fuels for certain alcohol fuels, related to tax and policies on buses, and provided incentives for van pooling.

Title III developed changes in business investment credit to encourage conservation of or conversion from gas and oil to encourage new energy technology. It included incentives for development of geothermal resources through an investment tax credit relating to drilling cost, depletion allowances, and other items involving drilling costs. The title denied investment tax credit on new gas and oil boilers.

96th Congress

Energy Security Act

The Energy Security Act (P.L. 96-294) was signed into law by President Carter on June 30, 1980. In enacting this law, Congress declared that the achievement of energy security within the United States was extremely important, that dependence on foreign energy resources should be significantly reduced, and that production of synthetic fuel in the United States would be a national goal.

The intent was to establish, as early as possible, practical commercial production of synthetic fuels from domestic resources using a wide variety of feasible technologies and to create commercial synthetic fuel production with the capacity of developing at least 500,000 barrels of crude oil per day by 1987 and 2 million barrels per day by 1992. The law created the U.S. Synthetic Fuels Corporation, a Federal entity of limited duration, to provide financial assistance to undertake synthetic fuel projects and to provide for financial assistance to encourage and insure the flow of capital funds to those sectors of the national economy to establish domestic production of synthetic fuels.

Title I of the act dealt with the development of synthetic fuel and the creation of the U.S. Synthetic Fuels Corporation, establishing the methods for setting up the corporation, financial assistance, corporate construction projects,

capitalization and finance, and other such items. It called for termination of the corporation September 30, 1997.

Title II dealt with biomass energy and alcoholic fuels and called for various programs to enhance development in these fields. Other titles included energy targets, renewable energy incentives, solar energy and energy conservation, geothermal energy, an acid precipitation program and carbon dioxide study. Title VIII dealt with the strategic petroleum reserve and required the President to resume the filling operations with specific directions toward the various reserves as they presently exist.

Other Federal Laws, Policies, and Regulations Affecting Energy Development

Federal Energy Regulatory Commission

Recent policies and regulations affecting hydropower development have occurred and are listed as follows:

1. In September 1978, FERC issued "Short-Form" license procedures for all projects with an installed capacity of 1.5 MW or less, the so-called "minor" projects. These procedures simplified the requirements for license applications.

2. On January 2, 1979, the chairman notified all major Federal agencies that preliminary permit applications would be processed by soliciting agency comments through FERC public notice procedures only. This procedure has reduced processing time to about four months when competing applications are not involved.

3. On October 22, 1979, the Commission issued regulations (Order No. 54, Docket No. 79-23) that prescribe general filing requirements and evaluation procedures applicable to both preliminary permit and license applications and simplify the regulations relating specifically to applications for preliminary permits, amendments to permits and cancellation of permits. The primary goal of the preliminary permit revisions is to eliminate all filing requirements that are not related centrally to the purpose of a permit. The revised regulations reduce the required filings from nine to four substantive exhibits.

4. On November 19, 1979, the Commission issued Order No. 59 which pertained to applications for major projects (capacity greater than 1.5 MW) using the water power potential of existing dams. This order reduced the number of required exhibits from 23 to 7.

5. Section 213 of the Public Utility Regulatory Act amended the Federal Power Act and granted FERC discretionary authority to exempt, in whole or in part, conduit hydro facilities from licensing requirements. On April 18, 1980, the Commission issued regulations (Order No. 76) setting forth the requirements for applications for exemption. Basically, these regulations are similar to the short form, except they are applicable to projects up to 15 MW and require less information than the short form. Under these regulations, all conduit hydro facilities are exempted within 90 days of receipt of an acceptable application. Projects subject to exemption are all projects on a manmade conduit, canal, pipeline, etc. used primarily for domestic, agricultural or industrial purposes that discharge flows used for hydropower into a conduit.

6. Since enactment of the National Energy Act, the Commission decided to delegate certain portions of its authority to the technical staff. Under this authority, the Director, Office of Electric Power Regulation (OEPR) issues permits and licenses for uncontested applications, i.e., there is no opposition to issuance, and an environmental impact statement must not be required. Most small-scale development licenses will be issued by the Director, OEPR, thereby reducing license processing time by two to three months. In a related matter, the Commission issued final regulations implementing section 210 of the Public Utility Regulatory Act on February 19, 1980, (Order No. 69). These regulations provide the rules that require utilities to purchase power from so-called "qualifying small power production facilities," including hydropower facilities up to 80 MW, provided that the facility owner sells or generates only electric power from cogeneration or small power production facilities. These regulations essentially provide the guidelines to State utility commissions for determining the revenues small hydropower developers would receive for power sales to utilities. Basically, the rates will be based on the incremental cost to the utility to produce an equivalent amount of power. The regulations also permit a qualifying facility owner to obtain an exemption from all Federal and State utility regulations, except licensing.

7. FERC suggested and the Congress adopted a suggestion to amend the Federal Power Act, section 30, to give the Commission discretionary authority to exempt hydropower projects up to 5,000 kW in size from Federal licensing. The Energy Security Act of 1980 granted the Commission the requested authority under certain conditions. On August 28, 1980, the Commission issued a notice of proposed rulemaking to implement the bill. Under the proposed rules, owners of sufficient rights to operate a specific 5 MW or smaller hydro project, or developers who have acquired an option to acquire these rights, could seek a licensing exemption. The project must use an existing dam or a "natural water feature," and may not be located on Federal lands. Standard exemption conditions would include times to start and finish construction, Commission enforcement powers, compliance with fish and wildlife requirements, navigation requirements, and in certain cases, dam safety provisions.

8. Simplified regulations have been proposed by FERC technical staff for unconstructed projects with an installed capacity of more than 1500 kW which will be adopted in the near future.

9. FERC on June 11, 1980, proposed regulations (Docket No. 80-31) that would consolidate and revise a number of its various orders, directives, and regulations related to dam safety. The new dam safety regulations would be included in part 12 (18 CFR 12) of FERC regulations.

Environmental Protection Agency

The general process of legislation/regulations is that the U.S. Congress establishes environmental legislation that provides a framework for State legislation and implementation of Federal and State regulations. State legislation and regulations can be more (but not less) stringent than Federal requirements if a State is delegated responsibility for administering the program in a given media. The Federal Government retains an oversight/reviewing role for those programs that are delegated to the States. State legislation in general parallels Federal legislation in form and substance. The following discussion highlights the major aspects of the legislative mandates of EPA as it applies to a synthetic fuels industry.

Clean Air Act. Under the Clean Air Act (P.L. 95-95) synthetic fuel facilities must: (a) employ best available control technology (BACT), (b) insure that national ambient air quality standards (NAAQS) (table 17) are not violated, (c) not violate the prevention of significant deterioration (PSD) ambient air quality increments (table 18) (40 CFR 52.21), (d) not significantly degrade visibility in mandatory class I areas (40 CFR 51), and (e) perhaps obtain up to one year of baseline data before applying for a PSD permit to construct and operate. BACT has been defined in the form of allowable emissions limits and control device operational characteristics. Source monitoring, ambient monitoring, record keeping, and reporting requirements are also part of the PSD permit. (40 CFR Part 60.7) Also EPA has the ability to request monitoring data, to take enforcement actions, and to take administrative and judicial actions if there are any emergency episodes of pollutants that present an imminent and substantial danger to public health.

Table 17

NATIONAL AMBIENT AIR QUALITY STANDARDS*

Pollutant	Averaging Time	Primary Standard (UG/M3)**	Secondary Standard (UG/M3)**
Sulphur Dioxide	Annual	80	---
	24-hour	365	---
	3-hour	---	1,300
Particulate matter	Annual	75	60
	24-hour	260	150
Nitric Oxide (as NO_2)	Annual	100	100
Ozone	1-hour	240	240
Carbon Monoxide	8-hour	10,000	10,000
	1-hour	40,000	40,000
Lead	Quarterly	1.5	1.5
Hydrogen Chloride (non CH_4)	3-hour	160***	160***

* 40 CFR Part 50
** Micrograms per meter cubed
*** Not a standard, a guide to show achievement of the O_3 standard

Table 18

PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY (PSD) STANDARDS*

Pollutant	Averaging Time	Maximum Allowable Increase (milligrams per meter cubed) Class I	Class II	Class III
Particulate matter	Annual	5	19	37
	24-hour	10	37	75
Sulfur Dioxide	Annual	2	20	40
	24-hour	5	91	182
	3-hour	25	512	700

*40 CFR 52.21 and 42 USC 7401 et seq section 163.

Notes:

1. Variances to the class I increments are allowed under certain conditions as specified at section 165 (d) (c) (ii) and (iii) and at 165 (d) (D) (i) of the Clean Air Act of 1977.

2. EPA was to have promulgated similar increments for hydro carbons, carbon monoxide, ozone, and nitric oxiode by August 7, 1979. They are under development. Increments for lead are due to be promulgated by Oct. 5, 1980.

Federal Water Pollution Control Act. The Federal Pollution Control Act is composed of four bills:

The Clean Water Act,
The Safe Drinking Water Act,
The Resource Conservation and Recovery Act, and
The National Environmental Policy Act.

Clean Water Act. The Federal Water Pollution Control Act amendments of 1972 (P.L. 92-500) established goals of (a) no discharge of pollutants into navigable streams by 1985, (b) attainment by July 1, 1983, of water quality suitable for protection and propagation of fish, shellfish, and wildlife and recreational use, and (c) prohibition of discharges of toxic amounts of toxic pollutants. The act contains requirements in sections 402 and 404 for potential permits for synthetic fuel facilities. A National Pollutant Discharge Elimination System (NPDES) permit must be obtained under requirements of section 402 if water is discharged to a navigable stream (defined as waters of the United States and in fact could be a dry creek bed which flows during runoff). Neither effluent guidelines (section 304) nor new source performance standards (section 306) have been promulgated for any synthetic fuels operations. However, in their absence, NPDES effluent limits are established

on a best engineering basis. A section 404 permit must be issued by the Army Corps of Engineers and concurred upon by EPA if any dredge and fill operations take place in a navigable stream (defined for 404 purposes as stream flow greater than 3 cfs). Section 303 of the act provides the mechanism for establishing water quality stream standards. Plans developed by State water pollution control agencies must define water courses within the State as either effluent-limited or water-quality-limited. Best management practices (BMP's) to control nonpoint source runoff may be defined according to sections 208 and 304(e) of the act.

Safe Water Drinking Water Act. Underground injection control (UIC) regulations proposed on April 20, 1979, (title 40 of the Code of Federal Regulations (CFR), Part 126) were promulgated in the May 19 and June 24, 1980, Federal Register. These regulations will govern the injection or reinjection of any fluids. Permits (40 CFR 122.36) will be required for in-situ operations and for mine dewatering reinjection. Various States require reinjection permits under existing regulations. The basic thrust of the UIC program is to require containment of reinjected fluids. Monitoring (40 CFR 146.34) and mitigation measures (40 CFR 122.42) to prevent the endangerment of the ground water system are requirements under these UIC regulations.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act (RCRA) governs the disposal of solid and hazardous wastes generated by a synthetic fuel facility. Criteria for the identification of hazardous wastes were proposed by EPA on December 18, 1978, (40 CFR, part 250). Final regulations were promulgated in the May 19, 1980, Federal Register (40 CFR 261-265). It appears that some high-volume, low risk materials will not be considered a hazardous waste. Instead, it will be subject to requirements at 40 CFR 257 (September 13, 1979, Federal Register). A concept of best engineering judgement will govern the disposal of hazardous wastes such as American Petroleum Institute separator sludge.

Testing of effects, record keeping, reporting, and conditions for the manufacture and handling of toxic substances are being defined under the auspices of the Toxic Substances Control Act (TSCA) of 1976. An inventory of all commercially produced chemical compounds was published in May 1979. If a substance is placed on the inventory, it is "grandfathered" from the TSCA premarket notification requirements. Ten synthetic fuels were identified on this list of 43,000 compounds. However, these ten are being reviewed to determine the validity of their being placed on the list. Being on the list does not "protect" a product from possible control requirements included in section 8. If a material is found to be a hazard, certain restrictions including labeling, precautionary handling requirements or even a ban on its production may be imposed by EPA.

National Environmental Policy Act. The final piece of environmental legislation in which EPA participates, which is relevant to synthetic fuels, is the National Environmental Policy Act (NEPA). EPA reviews, and in limited cases writes, the environmental impact statement when a project involves a major Federal action. EPA's role as a reviewer is to comment on the environmental aspects of the project.

EPA's legislation as described above normally provides a permit process mechanism. Companies wishing to construct and operate a synthetic fuel facility must receive a permit from EPA or from the State permitting authority in order for the facility to be operated.

Federal and State Pollution Control Regulations

Federal and State legislation generally prescribe the establishment of national and State environmental standards for a given medium (i.e., air, water, solid waste, etc.). Regulations designed to control emissions/effluents from an individual facility are promulgated to achieve the stated environmental standards. This section briefly describes this concept of standards/regulations. In almost all cases, the standards/regulations concept requires a developer to obtain a permit to construct and operate his facility. It is the intent of EPA to delegate the permit programs to the State.

Air

Regulations to protect air quality exist in two forms — ambient air quality standards and stack emission standards. All EPA regulations are codified in title 40 of the Code of Federal Regulations. Applicable parts are referred to in discussions of the various regulations below. Pursuant to section 109 of the Clean Air Act, EPA has established National Ambient Air Quality Standards (NAAQS) for seven criteria pollutants (40 CFR part 50). Primary standards are designed to protect public health, secondary standards to protect welfare (vegetation, materials corrosion, esthetics, etc.). States may also establish ambient air quality standards.

The Clean Air Act also established the concept of prevention of significant deterioration (PSD) of air quality designed to protect clean air areas (40 CFR Part 52.21). Class I areas include national parks larger than 2,428 hectares (6,000 acres), national wilderness areas greater than 2,023 hectares (5,000 acres), and international parks and national memorial parks that exceed 2,023 hectares (5,000 acres). Areas in the United States that presently have lower ambient air quality than that specified in the NAAQS are designated as nonattainment areas; the remainder of the United States is designated class II. Redesignation of class II areas to either class I or class III by the State is possible. Recent court rulings have resulted in some major changes in the PSD regulations which appear in the August 7, 1980, Federal Register.

A second ambient air quality consideration is the visibility protection afforded to Federal mandatory class I areas via section 169A of the Clean Air Act (40 CFR, Part 51). Regulations are to be promulgated by EPA (November 1980) and the States (August 1981) that are designed to prevent visibility impairment in the Federal mandatory class I areas. Since there are many issues to be resolved, it is too early to delineate the potential implications of the visibility regulations. Proposed regulations appeared in the May 22, 1980, Federal Register at 40 CFR 51.300. An EPA Report to Congress on visibility was published in November 1979.

Limitations on the amounts of pollutants emitted from a synthetic fuel facility are the enforceable mechanism to assure that the NAAQS and PSD increments are not violated. EPA establishes new source performance standards (NSPS) (40 CFR Part 60), States establish emission standards, and EPA (or the State) must define emission limits that reflect the Best Available Control Technology (BACT). NSPS have not been defined for synfuels facilities, but BACT has been defined for five oil shale facilities and one coal gasification facility through the PSD permit process.

Water

Water pollution control requirements exist in the form of water quality criteria, State water quality standards, drinking water standards, national pollutant NPDES limits, and effluent guidelines. The following discussion summarizes the major aspects of surface water and ground water quality standards; a complete discussion of the enforceable mechanism to attain these standards—the NPDES and UIC permit systems—may be found in an EPA report "Environmental Perspective on the Emerging Oil Shale Industry," November 1980.

Surface Water Quality Standards

Water quality standards are addressed in section 303 (Water Quality Standards and Implementation Plans) of the Clean Water Act. Excerpts and summaries of requirements for establishment and implementation of water quality standards of that section follow.

Water quality standards shall be reviewed at least every three years by the Governor or State water pollution control agency and shall be made available to the Administrator.

State revised or adopted new standards shall be submitted to the Administrator (EPA) for approval. Such revised or new water quality standards shall consist of the designated uses of the navigable waters involved and the water quality criteria for such waters based upon such uses. Such standards shall be to protect public health or welfare, enhance the quality of water, and serve the purposes of the Federal Water Pollution Control Act (FWPCA). Such standards shall be established, taking into consideration their existing or intended potential use and value for public water supplies, propagation of fish and wildlife, recreational purposes, agricultural, industrial, and other purposes, while also taking into consideration their use and value for navigation.

Each State shall identify those waters for which existing or proposed effluent limitations are not stringent enough to attain established water quality standards and establish waste load allocations for those waters. Regulations promulgated at 40 CFR 131.11 and further discussed in the December 28, 1978, Federal Register describe the Total Maximum Daily Load concept.

Each State shall identify those waters or parts thereof within its boundaries for which controls on thermal discharges are not sufficiently stringent to assure protection and propagations of a balanced indigenous population of shellfish, fish, and wildlife.

208 Process

Section 208 of the Federal Water Pollution Control Act required States to designate areawide waste treatment planning agencies. These 208 agencies are to plan, promulgate, and implement a program designed to protect surface water quality. Stream classifications and water quality standards are to be developed.

Local input in most States on the proposed stream use indicated a desire to assign multiple classification systems wherever possible. Although the apparent intent of the State classification systems (1978) is simply to identify the criteria applicable to a given stream segment, there is considerable local concern that a single use classification may be used later to restrict other uses, particularly agricultural ones. Intermittent streams have not been classified because of provisions made for this situation in the proposed classification system.

As an example, the four combinations of multiple use classifications that are proposed for Colorado include:

Class 1: Aquatic Life. Water Supply, Recreation, and Agriculture
Class 2: Water Supply, Recreation, and Agriculture
Class 3: Recreation and Agriculture
Class 4: Agriculture

The proposed water quality standards allow exceptions under certain conditions. Using the guidelines in the proposed criteria, the water quality data base, the proposed water quality criteria, the existing water quality problems, and a subjective analysis of effectiveness of potential control measures, three types of exceptions were identified for Colorado:

- Permanent exception - The current criterion limit is not valid for the drainage area because of natural environmental conditions. It is assumed that, given a return to prehistoric conditions, this parameter would still violate the criterion limit. The parameter should be monitored regularly, and any trend of increasing concentration would require evaluation/investigation of possible causes beyond natural conditions. It is further assumed that it is uneconomical to attempt controlling runoff.

- Temporary exception (10 Years) - This exception is requested when a criterion violation is identified as a possible consequence of man's activities in the basin and management strategies are available to improve water quality, but it will take 10 years to evaluate effectiveness.

- Temporary Exception (5 Years) - This exception is requested when a limited data base indicates a problem but more data are required to identify the cause, extent, and correctability of the problem. The 5-year exception should allow sufficient time for necessary additional data collection and analysis.

Ground Water Quality Standards

Federal regulations that may pertain to ground waters are addressed in the Safe Drinking Water Act. This act has most recently been interpreted as applying to well injection of waste into aquifers that serve or that might serve as sources for public drinking water. Such underground drinking water sources, while specified to include aquifers with less than 10,000 mg/l total dissolved solids, must have the potential to be sources of public water supply. Underground injection control (UIC) regulations were promulgated at 40 CFR 126 on May 19, 1980. In-situ operations will fall into the category of "class III wells." Drinking water standards are listed in table 19. Note that pits, ponds, and lagoons are not identified as underground injection sources at this time. They are covered under the Resources Conservation and Recovery Act.

Table 19

PROMULGATED DRINKING WATER STANDARDS (40 CFR 141)

The following are the maximum contaminant levels for inorganic chemicals other than fluoride:

Contaminant	Level (mg/l)
Arsenic	0.05
Barium	1.
Cadmium	0.010
Chromium	0.05
Lead	0.05
Mercury	0.002
Nitrate (as N)	10.
Selenium	0.01
Silver	0.05

When the average of the maximum daily air temperatures for the location in which the community water system is situated is the following, the maximum contaminant levels for fluoride are:

Temperature (°F)	Temperature (°C)	Level (mg/l)
53.7 and below	12.0 and below	2.4
53.8 to 58.3	12.1 to 14.6	2.2
58.4 to 63.8	14.7 to 17.6	2.0
63.9 to 70.6	17.7 to 21.4	1.8
70.7 to 79.2	21.5 to 26.2	1.6
79.3 to 90.5	26.3 to 32.5	1.4

The following are the maximum contaminant levels for organic chemicals. They apply only to community water systems. Compliance with maximum contaminant levels for organic chemicals is calculated pursuant to section 141.24.

Organic Chemical	Level (mg/l)
a. Chlorinated hydrocarbons:	
Endrin (1,2,3,4,10, 10-hexachloro-6.7-epoxy-1,4,4a,5,6,7,8a-octahydro-1.4-endo-5,8-dimenthano naphthalene).	0.00002
Lindane (1,2,3,4,5,6-hexachlorocyclohexane, gamma isomer).	0.004
Methoxychlor (1,1,1-Trichloro-2,2-bis p-methoxyphenyl) ethane).	0.1
Toxaphene ($C_{10}H_{10}Cl_8$-Technical Chlorinated camphene. 67-69 percent chlorine).	0.005
b. Chlorophenoxys:	
2,4-D, (2,4-Dichlorophenoxyacetic acid).	0.1
2,4,5-TF Silvex (2,4,5-Trichlorophenoxypropionic acid).	0.01

Solid and Hazardous Wastes

The RCRA requires that solid and hazardous waste generators and transporters receive permits and that wastes be disposed only by safe practices. Regulations have been promulgated at 40 CFR Part 261 for: (1) the criteria to identify solid and hazardous wastes (section 3001); (2) disposal standards (section 3004); and (3) permit programs (section 3005). If a waste is not defined as hazardous (i.e., it is defined only as a solid waste) disposal will be governed by the section 4004 regulations as promulgated at 40 CFR Part 257 on Sept. 18, 1979. The promulgated regulations defined a waste as hazardous if it is ignitable (flash point less than 60° C or 140° F), corrosive (extract pH less than or equal to 2 or greater than 12.5), reactive (explosive or oxidizing), or toxic (extract concentration is 100 times greater than drinking water standards). Overburden mine wastes that are returned to the mine are exempt from these regulations. Also, materials ready for further processing are exempt.

Resources Conservation and Recovery Act regulations probably will result in materials such as American Petroleum Institute separator sludge, spent catalysts, gasifier ash, distillation tank bottoms and perhaps others being defined as hazardous wastes.

STATE

This section presents a review and summary of energy policies, institutional arrangements, and legal statutes and regulations pertaining to electric power for each of the 10 basin States. Therefore, it represents, to a large degree, State complement to the Federal laws reviewed previously.

The information presented in this section is arranged in two categories: State energy policy and program organization; and general and specific State statutes pertaining to energy development, electric power, State policies, and pending legislation. Each State's individual activities are briefly summarized under those section headings.

State Energy Policy and Program Organization

Colorado

In early 1977, the State of Colorado completed preparation of its four-year, statewide Energy Conservation Plan, as provided for by title III of P.L. 94-163. The overriding intent of the plan, developed according to Federal Energy Agency (FEA) national guidelines, is to increase conservation and efficiency in the end-use of all forms of energy by both the public and private sectors in the State. Specifically, the comprehensive State Energy Conservation Plan calls for an 8 percent reduction in the projected 1980 energy consumption level in Colorado. Attainment of the 8 percent figure would represent a substantial improvement over FEA's mandatory planning requirement of a 5 percent consumption reduction.

The final version of the plan incorporates a series of 24 voluntary, educational, and mandatory program measures to realize the overall planning objective. Moreover the plan includes five broad elements designed to further State energy conservation efforts. These include: (1) programs to provide training and technical assistance in the State's commercial and industrial sector; (2) programs relating to State government operations; (3) programs covering new construction, renovation, and weatherization of buildings; (4) public and agricultural education programs; and (5) programs relating to transportation. Finally, the plan strongly recognizes the immediate need to begin converting to renewable, alternative sources of energy.

Colorado's energy conservation policy has been one of attaining conservation through education and renewable energy tax incentive programs. These are promulgated through the Colorado Office of Energy Conservation. No State mandates have been issued. Substantial savings have been effected in automobile fuel consumption, in spite of a growing propulation. The rate of growth in electrical and natural gas consumption has declined since the inception of the program in 1977.

Further information about State energy programs can be obtained from the Department of Natural Resources. To supplement energy activities of the Department of Natural Resources, the Governor of Colorado formed an Energy Planning Coordinating Council in January 1976 to oversee interdepartmental energy policy and program analyses. For more information, write Department of Natural Resources, 1313 Sherman Street, Room 718, Denver, CO 80203.

Iowa

The Revised Iowa Energy Conservation Plan, submitted to the Department of Energy by the Iowa Energy Policy Council in 1979, is a revision of the original State energy conservation plan developed in 1977. The original plan's goal was to reduce Iowa energy consumption in 1980 by 8 percent under projected energy use. Initial estimates of energy avoidance/savings from the first two years of the program indicated that Iowa had essentially achieved this goal.

Voluntary and mandatory programs in seven economic sectors were outlined in the revised plan. Programs in agriculture, government, transportation, utilities, industries, commercial and residential sectors were included. The plan also incorporates four of FEA's five mandatory energy conservation programs: lighting efficiency standards for public buildings; promotion of availability and use of carpools, vanpools, and public transportation; energy standards affecting State and local procurement practices; and thermal efficiency standards for new and renovated buildings. Because Iowa had inaugurated a "right turn on red after stop" provision in 1975, additional energy savings realized as a result of this mandatory program were not incorporated into the conservation plan.

Specific programs to affect direct energy savings in the electric utility sector that have been outlined by the plan include promotion of cogeneration of electricity and heat and the promotion of allocation of utilities and industry; utility load management; utility advertising for energy conservation; and infrared line inspection; and use of solid waste as a fuel by utilities; and a municipal utility study.

Established in 1975, the Iowa Energy Policy Council has the task of developing energy policies and carrying out energy programs in Iowa. The 19-member council, composed of private citizens, State officials, and State legislators, and its staff have been involved in an extremely broad range of state energy activities. In particular the council has worked to develop energy emergency plans and reliable fuels data, establish a statewide energy policy and energy conservation program, give assistance in energy management programs, and encourage the development of alternate forms of energy.

For further information about the council's activities write Iowa Energy Policy Council, Capitol Complex, Des Moines, IA 50319.

Kansas

Kansas Governor John Carlin presented Kansas' 1979-1980 Energy Policies as follows:

> State government must use all of its available resources and influence to address the energy needs of the citizens of Kansas. We must not remain idle and allow the Federal Government to mandate Kansas energy policy. Nor can we afford to casually place our fate in the hands of energy suppliers. We must seize every opportunity to determine our own destiny in this area which is so vital to our well-being.
>
> While this administration was successful in securing legislative approval this past session of two major legislative items dealing with the siting of electric generation facilities and the pricing of natural gas, much remains to be done to insure our energy security at a reasonable cost.
>
> This administration is committed to improving efforts by State government to increase energy conservation, encourage the research and development of alternate energy technologies, and to insure the continued availability of reasonably priced supplies of energy.
>
> Accordingly, I have set the following directions for State government in the area of energy for the next year: To continue to promote legislation designed to prevent unnecessary utility rate increases. To promote energy conservation efforts by local governments, private industries, and private homeowners. To identify and develop methods by which State government can assist Kansas energy consumers who are on fixed or limited incomes in paying their bills and increasing the energy efficiency of their homes. To devote increased Federal and State government resources to the development and application of solar, wind and other promising alternate energy technologies which do not pose long-term health hazards. To develop improved capacity for forecasting energy needs. To develop a broad and comprehensive state energy plan that provides the ongoing basis for clear and decisive action by State government to conserve energy, promote the development of alternate energy technologies, and work for the development of

responsive and fair Federal energy policies. To assist communities in developing programs to promote their energy self-sufficiency. To develop improved capacity for addressing shortages of all conventional fuels and energy forms that are needed to sustain our level of economic activity and standard of living. To explore alternative utility rate structures which are conducive to energy conservation.

The basic responsibility of the Kansas Energy Office (KEO) is to propose a comprehensive State energy strategy to the State's public decision-makers; once such a strategy (or elements thereof) is adopted, to assume a key role in pursuing its implementation; to serve as an information and analysis resource for the Governor and the Legislature in their energy policy deliberations; to provide direct assistance to Kansas citizens as they seek to modify, to minimize threats to the public welfare which may be posed by energy product shortages.

To fulfill its mission, KEO is organized into four major activity divisions: (1) planning and fuel allocation, (2) research and resource development, (3) conservation and solar applications, and (4) administration. Major responsibilities include: administration of State responsibilities under Federal fuel allocation programs; development of a system of priorities for the distribution of energy products during an energy emergency; development of educational programs to promote energy resource development; energy contingency planning; energy data collection and analysis; energy conservation analyses in State government; establishment of an energy information center; establishment of computer programs for aiding the public in making investment decisions regarding installation of insulation and solar systems; preparation of a biennial report to the Governor and the Legislature; energy demand forecasting; and energy research and development program development and administration.

- Planning and Fuel Allocation Division. The fuel allocation program changed from a near-dormant function to having a substantial workload. Requests for set-aside fuel increased from 26 in January of 1979 to a total of 1,520 in July of 1979. To handle the expected workload in the future, the 1980 legislature approved $22,500 in State funds for automating the State set-aside program. A significant program development of this Division is the completion of the initial stages for development of a Kansas Energy Information System, a system which will eventually supply up-to-date information and data on energy supplies, demand, and consumption to State officials.

- Research and Resource Development Division. The Division identified several innovative energy opportunities in the State—among them, cogeneration potential of natural gas compressor stations and municipal powerplants; use of municipal and animal waste as energy resources; the use of certain vegetable oils as fuels; and the potential of butanol as fuel. KEO obtained grant funds from the Ozarks Regional Commission to perform a feasibility study of small-scale ethanol production and to implement the first phase of an energy forest project on abandoned mined lands in southeast Kansas.

- Conservation and Solar Applications Division. Of prime importance was the passage of legislation authorizing bus subsidies for State employees, implementation of a pilot vanpool program for State employees, and the use of life-cycle cost considerations in State procurement. These programs will be operated by the Department of Administration with the help of KEO. In addition, the 1980 Legislature appropriated $50,000 from the State General Fund for KEO's solar program, and significantly enhanced the State's solar tax incentive laws.

One of the most important developments in FY 1979 was the implementation of the Institutional Building Conservation Program. The program offers energy audits, technical assistance in energy conservation and in some instances, grants of up to 50 percent of the cost for energy saving capital improvements to targeted institutions. By the end of July 1980, 536 institutions, covering 2,445 buildings, had participated in the program. Of these buildings and institutions, a total of 26 schools and hospitals received $1.5 million in grants for energy saving capital improvements. Another 138 buildings (schools, hospitals, local units of government) received $129,000 for professional energy analyses conducted by an engineer or architect.

Information services were expanded during the last two years. Public service presentations were made at the Kansas State Fair. The Information Center coordinated much of the High Plains Energy Forum in Dodge City. This forum, conducted in the fall of 1979, addressed a wide range of conservation and renewable energy opportunities. A contract, negotiated with Kansas State University at the close of FY 1980, will establish a technical information center at Kansas State University. Finally, KEO initiated a two-year program for the introduction of an energy curriculum in grades K through 6.

Specific conservation programs have also been initiated which affect energy usage and conservation in State government. At the end of FY 1980 the KEO began a program to conduct energy audits of approximately 550 of the State government's largest buildings. The audits will be used to develop a cost-effective strategy for energy conservation in State-owned buildings.

During fiscal year 1980, approximately 10,000 home energy audits were conducted through KEO's Project Conserve Program. The Energy Office began the process of developing a contingency plan to be implemented in the event of gasoline shortages. Additional conservation programs include: home energy conservation workshops; a ride-sharing program in the Kansas City Metropolitan area; a conference on energy conservation in schools; workshops addressing energy conservation in boiler operations; and development of a community energy management system in the Southwest Regional Planning Commission area.

Solar programs have been expanded significantly. KEO has completed the preparation of computerized cost-benefit analysis services for solar system purchases. KEO has been encouraging local governments to apply for funds to be used to implement solar applications. KEO assisted nine Kansas communities in applying for the Department of Energy Solar Thermal Program. Osage City is a finalist in the project competition.

For further information about State energy programs write Kansas Energy Office, 214 W. 6th Street, Topeka, KS 66603.

Minnesota

The Minnesota Energy Agency (MEA) has the responsibility for directing numerous State energy activities and programs. Foremost among the agency's responsibilities are an information and education program; the provision of service assistance to local areas and units of government; the development and analysis of State energy policy; the operation of a centralized energy data system; the supervision of State energy research activities; the development of energy demand and supply forecasts; the formulation of an emergency fuel allocation plan; certification of the need for all large energy facilities; the development of a State energy conservation program; and the preparation of a biennial State Energy Policy and Conservation Report. The State energy agency has also been involved in preparing and submitting energy-related legislative proposals to the State legislature for their consideration and action.

The Minnesota Energy Conservation Plan, submitted to the Federal Energy Administration by MEA on March 28, 1977, estimated that a 9.5 percent reduction in energy consumption over projected levels was achievable for calendar year 1980.

MEA is promoting energy conservation in the areas of residential, commercial-institutional, and industrial use; new buiding design and construction; transportation; agriculture and other land use. Development of public information, (including "self-audit" materials, energy education curricula, and regional energy information centers), and community outreach (promotion of community-based energy planning) are major areas of emphasis. Other activities included in the energy policy and conservation program include government procurement programs, enforcement, ongoing program planning and evaluation, and alternative energy development.

MEA programs in alternative energy development have included solar research and a solar information office (in conjunction with the Mid-America Solar Energy Center), wind, and cogeneration/district heating programs. Small-scale alternative energy demonstration projects have been supported with funding from the Legislative Commission on Minnesota Resources. In addition MEA has been working with the Department of Natural Resources to develop the State's hydropower and peat/special energy crops resources.

MEA's 1980 Biennial Report to the Legislature (Draft 1980 Energy Policy and Conservation Report) includes a 20-year forecast of supply and demand and a discussion of existing and potential State energy actions. MEA assesses major energy strategies in terms of: direct economic costs, net economic benefits, resource availability, and environmental and social costs. MEA concludes that,

> "while wisely managing available supplies of traditional fuels, Minnesota should focus on conservation and Minnesota-based renewable resources as the keys to our energy future. Utilizing these resources instead of continuing our complete dependence on traditional fuels will strengthen Minnesota's economy, provide more jobs, improve the environment, and reduce our vulnerability to foreign supply interruptions."

The Minnesota Environmental Quality Board (EQB) has been given the authority for power plant and transmission line siting. In line with this responsibility, EQB has been studying: (1) the comparative economic and technical feasibility of various power plant capacities greater than 50 MW, and the total effects of various combinations of plant sizes; (2) opportunities for local and regional community and economic development associated with the colocation of power plants and industry; and (3) the siting opportunities and impacts associated with various alternative electric energy generation systems that are greater than 50 MW.

For additional information about the State's energy activities and programs write Minnesota Energy Agency, Room 980, American Center Building, 150 East Kellogg Boulevard, Saint Paul, MN 55101.

Missouri

By realizing all the energy conservation objectives established in a recently prepared State Energy Conservation Plan, Missouri would reduce its projected 1980 energy consumption by 5.2 percent. Missouri was only able to obtain 4.4 percent of the 5.2 percent projected figure for 1980 to reduce energy consumption. Energy price increases and industrial economics and practices attributed for the larger share of reducing energy consumption which would put the State's overall reduced energy consumption at roughly 7.3 percent. The State's basic purpose in pursuing a strong energy conservation approach, as outlined in the plan, is to reduce waste and to end the inefficient use of energy in the State.

As submitted to FEA, the Missouri plan contains a series of 14 program measures that, when implemented, will effectively achieve the State conservation goal. Collectively, the 14 measures include 5 FEA-mandated responses and 9 voluntary conservation activities.

In addition to program measures covering the residential, industrial, commercial, State and local government, transportation, agricultural, and resource recovery sectors, the plan includes a variety of energy conservation management approaches specifically targeted at the utility sector. The utility conservation measures covered in the plan largely emphasize the reformation of existing utility policies that encourage the use of excessive quantities of energy.

Specific State actions proposed in the plan include: (1) the proposed establishment of a program where gas and electric utilities would actively promote and provide assistance in residential conservation efforts, to include weatherstripping, installing automatic thermostats, and increasing insulation levels; (2) the issuance of ired certificate of residential and commercial structure energy efficiency prior to permitting building hook-ups to utility service; (3) restrictions on master-metering for new commercial buildings and multifamily dwelling units; (4) the promotion of a load management program to encourage ripple control, power pooling, and rate restructuring by time-of-day and interruptible rates; and benefit/cost evaluation of small-scale power generation facilities, cogeneration, and waste heat recovery; (5) controls on the nonessential use of lighting; and (6) a requirement that utilities develop energy conservation materials and promote energy conservation education and public awareness.

State Position on Increasing Water and Energy Demands vs. Conservation of Water and Energy. Minnesota has been aggressively pursuing energy conservation, especially in the residential and commercial sectors. The State energy agency also has a policy of discouraging the substitution of electricity for fossil fuels for space heating, as a method of dampening electricity demand. Electric power production is Minnesota's largest water withdrawal use, and third largest consumptive water use; reductions in projected electrical demand are the major cause of reductions in Minnesota's projected water use. Additionally, the State is examining cogeneration/district heating as a way of increasing efficiency of fuel use in power plants, thereby reducing water requirements associated with electric power production.

The Minnesota Department of Natural Resources is directed by statute to "conserve and utilize the water resources of the State in the best interests of people of the State." (M.S. 105.38). Efficiency of use is one of the considerations in the DNR's water appropriation permit program, and in DNR's water appropriation conflict resolution process.

In 1978-1979, the Water Planning Board studied water conservation potential in residential, irrigation, and food processing. Current Water Planning Board activity includes an investigation of industrial and municipal water conservation possibilities, as well as relationships between water and energy conservation, and areas where they might be simultaneously achieved.

Anticipated Future State and Local Legislation, Programs, and Policies Pertaining to Energy Production and Management. The Minnesota Energy Agency in its 1980 Biennial Report to the State Legislature stated three broad goals:

1. To maintain an adequate supply and equitable distribution of traditional fuels.

2. To promote the development of nontraditional energy sources, especially those that are renewable.

3. To promote the conservation of scarce energy resources in all sectors.

It is unlikely that new programs will be enacted in these areas in 1981, however, due to current fiscal constraints.

Legislation may be expected to carry out recommendations of the Peat Policy Project recently completed by the Department of Natural Resources (especially regarding reclamation of mined peatlands). Legislation closing gaps in the regulatory framework surrounding uranium mining may be expected if such development does occur.

Missouri

Energy Facility Siting. Recent legislation involving siting laws in Missouri met with no success. However, the Missouri Public Service Commission (PSC) maintains jurisdiction over the manufacture of electricity in the State. (The Commission only regulates investor-owned facilities. It does not regulate municipal facilities and only regulates co-ops for safety reasons, or if a facility is outside its service area.) As a result, the permission and approval of the PSC is necessary before any electric generating plant may be constructed. Such approval is based on whether the facility is necessary or convenient for public service. The commission is also responsible for investigating the methods and nature of energy supplies and ordering service improvements when necessary.

Under the established State Energy Conservation Plan, Missouri has expanded its voluntary conservation efforts and has acted on the five Department of Energy mandated responses. The principles of the plan are specifically tailored to capitalize the virtues of ingenuity for developing alternate sources of energy that are independently capable of demonstrating cost effectiveness and savings to the consumer, to develop systematic approaches for energy use efficiency that eliminates reactionary energy crisis planning, and to do this without shifting the expense to other natural resources or to the detriment of community and environment. Missouri is still pursuing State actions as described before, to further conservation efforts.

The State of Missouri's Energy Program is located within the Division of Policy Development in the Department of Natural Resources. The agency's mission is to assist the State in meeting its energy needs by recommending or developing laws, programs, procedures, and policies that assure the wise and efficient use of energy. The agency has adopted three basic goals which currently are among the highest priority objectives of the Department of Natural Resources: (1) to promote State utilization of alternate energy resources for industry, business, institutions, and residential customers; (2) to develop and maintain program capability to effectively manage State energy supply and distribution problems; and (3) to reduce energy consumption by 5.2 percent of the State's 1980 projected energy use. In addition to the energy agency, several ad hoc advisory bodies such as the Governor's Commission on Energy Conservation, the Committee of Building Technology Advisors, the Weatherization Advisory Committee, and a solar advisory group serve the department and the energy agency with technical advice and recommendations.

For additional information about State energy activities in Missouri write Missouri Energy Program, Department of Natural Resources, P.O. Box 1309, Jefferson City, MO 65101.

Montana

With the completion of The Montana Energy Conservation Plan, the conservation of energy emerged as the keystone of Montana's intermediate and long-term energy policy. Twenty-two discrete program measures are contained in the plan and are intended to promote the efficient utilization of energy in the State. These measures include activities that target residential, commercial, transportation, and agricultural sectors.

Energy-related responsibilities are shared by several administrative agencies in Montana. The Energy Division and the Facility Siting Division of the Department of Natural Resources and Conservation (DNRC) play a major role in carrying out Montana's energy-related programs and policies. In addition to the Energy Division and the Facility Siting Division, the Water Resources Division and the Oil and Gas Conservation Division of DNRC are actively involved in various aspects of the energy program.

Energy Division. The Energy Division was restructured in November 1979 and separated into two divisions within DNRC. Responsibility for energy facility siting activities was assumed by a newly created Facility Siting Division, except for energy need analysis and alternatives, which remained with the Energy Division. The Energy Division has a broad range of responsibilities, carried out by four bureaus: Conservation, Fuel Assistance, Planning and Analysis, and Renewable Energy.

The Conservation Bureau administers several programs under Federal law and regulation including: the State Energy Conservation Program, the Emergency Building Temperature Restrictions Program, the Energy Extension Service Program, and the Institutional Building Grants Program. A new program which the bureau will implement in 1981 is the Residential Conservation Service Program.

The Fuel Assistance Bureau is responsible for alleviating emergency and hardship petroleum fuel problems, assisting end users in obtaining fuel supplies, and maintaining contact with oil companies and petroleum dealers. The bureau is also responsible for the administration of the state set-aside operation.

The Planning and Analysis Bureau has responsibility in four areas: (1) analysis of the need for and alternatives to proposed major energy conversion and transmission facilities; (2) analysis of alternative energy futures for Montana; (3) design and oversight of energy emergency planning and procedures; and (4) collection and dissemination of energy information. The bureau also handles energy policy analysis and assists in energy program planning.

The Renewable Energy Bureau administers the Alternative Renewable Energy Sources Program making grants to projects which demonstrate, develop, or research some form of nonfossil energy. This program is funded through revenues from the State coal severance tax. The bureau also administers the Montana Geothermal Commercialization Program, and the Western SUN State Solar Office. The bureau also provides technical information and assistance on renewable energy to private and public individuals and organizations.

Facility Siting Division. The Facility Siting Division of DNRC has responsibility for administering the Major Facility Siting Act (MFSA) and for evaluating certain projects under the Montana Environmental Policy Act (MEPA). The MFSA provides for comprehensive review of proposals to construct and operate certain kinds of facilities for generating, converting, or transmitting energy in Montana. To ensure that such facilities are needed and that adverse impacts are minimized, such facilities must receive a certificate of environmental compatibility and public need from the Board of Natural Resources and Conservation.

Water Resources Division. The Water Resources Division administers DNRC's water resource programs. Included in its functions are administering the Montana water rights law, preparing the State water plan, operating, maintaining and constructing State-owned water resource projects, managing flood plains, studying river basins, and administering the weather modification, dam safety, technical assistance, and renewable resource development programs.

The Division is responsible for a master contract arrangement with the Bureau of Reclamation which permits Montana to administer subcontracts with potential industrial users of water from Fort Peck Reservoir.

The Division also participates in energy-related studies sponsored by the Pacific Northwest River Basins Commission and the Missouri River Basin Commission. In addition the Division has worked in cooperation with the International Poplar River Water Quality Board to assess the impacts of Canadian coal conversion on water quality in Montana. The Division also coordinated the State's response to the Army Corps of Engineers National Hydroelectric Power Study (NHPS).

The State owns some 35 major water conservation projects as well as a number of small projects, some of which are no longer active and most of which are physically deteriorated. In March 1978, the Board of Natural Resources and Conservation adopted a "Conceptual Plan for Montana Water Resources Projects." The plan proposes hydroelectric facilities at State-owned dams and subsequent sale of the electricity through long-term contracts. The revenue thus derived will enable the State to repair and maintain existing projects and to construct new ones. The expertise gained from this process will also allow the State to provide assistance and advice to private owners of water projects who wish to undertake similar hydroelectric development plans.

In April 1980, the Water Resources Division received a grant from DOE to explore further the role that small-scale hydropower will play in Montana's energy future. DNRC will assist the Federal Government by: (1) further defining the State's most promising dam sites, identifying the owners of each site, conveying the program benefits to the owners, and encouraging site development; (2) expediting site development through State and local processing; (3) providing small-scale hydro developers with guidance and information regarding State and Federal funding assistance and the major factors to be considered in the overall project; and (4) promoting small-scale hydroelectric power development.

The Water Resources Division receives applications for water use permits from present as well as potential water users. Among these applications are those for industrial use which could include large energy developments.

Other State Agencies. Numerous other State agencies are also active in various energy related roles in Montana.

The Department of Fish, Wildlife, and Parks has ongoing programs to study the effects of energy development on wildlife habitat, populations, both game and nongame, fisheries, and the impacts of ecosystem modification.

The Department of Health and Environmental Sciences deals with all aspects of the quality of health/air/water resulting from energy development and production. The Department also administers State regulations pertaining to the solution extraction of uranium.

The Department of Community Affairs has the Coal Board which administers the sections of Montana's coal development impact legislation which establish the coal impact grant program for local governmental units in coal impact areas. The Department also administers the home weatherization program, fuel bills assistance programs, the local energy emergency preparedness and prevention program, and various energy impact assistance programs.

The Department of Highways deals with coal area road impacts and has recently participated in a multi-State coal haul roads study. The Department has

become substantially involved with petroleum fuel conservation for State motor vehicles and has recently become more active in disseminating information concerning vanpooling and carpooling to the larger urban areas in Montana.

The Department of Revenue administers most of the State's tax programs. Energy-related taxes include the coal severance tax, the coal gross proceeds tax, the oil and gas producers severance tax, the oil and gas net proceeds tax, the resource indemnity trust tax, the electrical energy producers license tax, the gasoline distributors' license tax, and the special fuel tax. Energy-related tax incentive programs administered by the department include an income tax credit and property tax exemption program for installtion or renewable energy systems, and an income tax deduction for energy conservation measures.

The Lieutenant Governor's Office has had responsibility over the past few years for energy policy formation and coordination. In 1979-80 the Lieutenant Governor's Office was involved in several energy-related issues of particular importance to Montana, including the Federal Government's coal leasing program, the U.S. Department of Energy's forecasts of regional coal production, and several proposed Canadian energy developments near Montana's border. The Lieutenant Governor's Office has also closely monitored proposed Federal legislation dealing with regional energy planning in the Pacific Northwest, emphasizing Montana's position and participation.

Other State agencies, such as the Environmental Quality Council, the Department of Administration, the Department of Agriculture, the Department of Business Regulation, and the Consumer Counsel Office all have responsibilities in the energy area.

For further information on Montana's energy programs write Montana Department of Natural Resources and Conservation, 32 South Ewing, Helena, MT 59620; or call (406) 449-3712; Energy Division, (406) 449-3780; Facility Siting Division, (406) 449-4600; Water Resources Division, (406) 449-2872.

Nebraska

The Nebraska Energy Conservation Plan was completed in 1976 incorporating a number of energy conservation measures to achieve an energy savings goal of 6.7 percent from the time they went into effect on October 1, 1977 through 1980. In addition to the five federally mandated FEA programs, Nebraska identified the following measures to be confronted by the State plan: lighting and thermal efficiency standards; cars, van pools and public transportation; procurement standards; and right-turn-on-red, all of which are mandatory. In addition, the State plan also addresses commercial, residential, and agricultural energy use efficiency; utility energy conservation; solid waste management; data collection; waste oil collection; energy emergency and curtailment; public information on energy; industrial energy audits; and governmental operation. The Nebraska Energy Conservation Supplemental Plan also requires activity in the areas of intergovernmental energy coordination, energy audits, and energy education.

The Nebraska Energy Office (NEO) is a nonregulatory agency which was first established by executive order in 1976. In turn, the State Legislature established the Nebraska Energy Office as a formal agency of State government in 1977 to advise the Governor directly on energy policy. The State Legislature revised the duties assigned to the NEO in 1979 to include the following:

1. To serve as or assist in developing and coordinating a central repository within State government for the collection of data on energy;

2. To undertake a continuing assessment of the trends in the availability, consumption and development of all forms of energy;

3. To collect and analyze data relating to present and future demands and resources for all sources of energy and specify energy needs for the State;

4. To recommend to the Governor and the Legislature energy policies and conservation measures for the State and to carry out such measures as are adopted;

5. To provide for public dissemination of appropriate information on energy, energy sources, and energy conservation;

6. To accept, expend, or dispense funds, public or private, made available to it for research studies, demonstration projects, or other activities which are related either to energy conservation or development;

7. To study the impact and relationship of State energy policies to national and regional energy policies;

8. Engage in such activities as will reasonably insure that the State of Nebraska and its citizens receive an equitable share of energy supplies, including the administration of any Federal or State mandated energy allocation programs;

9. To actively seek the advice of the citizens of Nebraska regarding energy policies and programs;

10. To prepare emergency allocation plans suggesting to the Governor actions to be taken in the event of serious shortages of energy;

11. To design a State program for conservation of energy;

12. To provide technical assistance to local subdivisions of government; and

13. To provide technical assistance to private persons desiring information on energy conservation techniques and the use of renewable energy technologies.

The law further provides the NEO with authority to adopt rules and regulations to implement the duties assigned to it by law. Regulations have been proposed concerning thermal and lighting efficiency standards, implementation facilities and measures qualifying for energy conservation loans by the Nebraska Mortgate Finance Fund.

Governor Charles Thone is taking action to create a central office for energy activities. He has designated the Nebraska Energy Office as the lead agency giving it the job of coordinating and formulating energy policy. The NEO will coordinate the activities of the Power Review Board, the Oil and Gas Conservation Commission and the Alcohol Products Industrial Utilization Committee (Gasohol).

One specific program which has been implemented in certain areas with positive results in energy conservation is load management involving the shift of irrigation load demands to off-peak hours. In addition, a 650 MW hydroelectric power plant has been proposed for development by the Nebraska Public Power District (NPPD) on the Middle Loup River at Comstock, Nebraska.

For further information about energy activities and programs in Nebraska, write Nebraska Energy Office, P.O. Box 95087, State Capitol Building, Lincoln, NE 68509.

North Dakota

On March 28, 1977, the North Dakota Office of Energy Management and Conservation submitted the State's official 4-year Energy Conservation Plan to FEA. As stated in the plan, the State's specific energy conservation goal is to reduce North Dakota's 1980 energy consumption by 7.5 percent, or by an amount equivalent to 12.3 trillion Btu's.

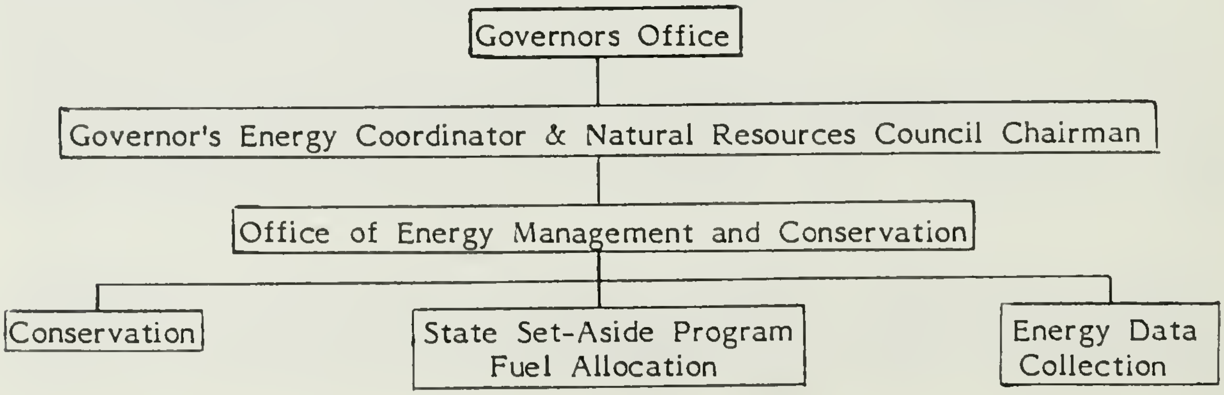
In its present form, the North Dakota Energy Conservation Plan incorporates five FEA-mandated conservation measures, as well as voluntary programs in the agricultural, residential, industrial, and State government sectors. In all program measures, the State has strongly recognized the need for a public education component.

Conservation programs that specifically involve North Dakota electric utilities include conducting a computerized audit of energy use in single family, owner-occupied homes through a program titled "Project Conserve," and instituting an effective load management program Project UCAN (Utilities Conservation Action Now).

Major energy activities in North Dakota fall within the purview of the State's Office of Energy Management and Conservation. Specific responsibilities of the office include coordination of energy and conservation programs throughout the State, development and collection of energy availability and fuel consumption data, and administration of the State's fuel allocation program. The administrative position of the office within North Dakota's governmental organization is shown in figure 3.

Figure 3

ENERGY ADMINISTRATION IN NORTH DAKOTA STATE GOVERNMENT



For more information about energy policies and programs in North Dakota write Office of Energy Management and Conservation, Third and Main Streets, Bismarck, ND 58505.

South Dakota

In an attempt to specify immediate solutions to recent energy problems and to guide future energy conservation activities, the State Office of Energy Policy (OEP) prepared and submitted a Comprehensive Energy Conservation Policy Plan for South Dakota to FEA in March of 1977. The overall goal of the plan is to reduce projected gross energy consumption increases for 1980 by 6.2 percent. If realized, the reduction would result in a per capita energy savings of 19 million Btu's in 1980.

In developing the plan, OEP identified seven major areas (six consumption sectors and a public education component) in which conservation measures and activities could be implemented: (1) agriculture, (2) commerce/industry, (3) energy suppliers, (4) residences, (5) State/local government, (6) transportation, and (7) public education. The designation of 61 individual conservation program measures for the seven sectors, when combined with FEA's five mandatory programs, serves to solidify the State's two-fold conservation strategy of producing immediate energy savings through improving energy use efficiency and educating the public on the long-term need to conserve energy resources. Additional policy approaches emphasized in the plan include the development of alternative and renewable energy resources and State cooperation in devoting special attention to the needs of South Dakota's native American population.

Six specific conservation programs have been proposed for the energy suppliers sector in the South Dakota Conservation Plan. The six include expansion of four existing conservation programs and the introduction of two new programs. The four existing programs to be expanded consist of: (1) the use of remote sensing thermograms to detect building heat loss; (2) the provision of building weatherization incentives by energy utilities; (3) the development of conservation plans, containing measures such as those recommended in FEA's Conservation and Load Management (CALM) Program, by energy suppliers; and (4) utility efforts to shift electric loads to off-peak demand periods. The two new programs include conducting energy audits and encouraging cogeneration through planned facility siting.

The responsibility for State energy management was assigned to the South Dakota Office of Energy Policy by executive order of the Governor in July 1974. The authority delegated to the office includes administration of the State set-aside program for fuel allocation, promotion of energy conservation, collection and dissemination of information necessary to formulate energy policies, and evaluation of State energy policies and programs. The office was also assigned the task of preparing the State's Energy Conservation Policy Plan.

For more information on South Dakota's energy programs write Office of Energy Policy, Capital Lake Plaza, Pierre, SD 57501.

Wyoming

A 7.5 percent reduction in projected energy consumption could be realized by 1980 in Wyoming if the program measures outlined in the State's Energy Conservation Plan are successfully implemented. The State Plan, submitted to FEA

in March 1977, outlines 12 primary and numerous secondary programs to achieve the 7.5 percent reduced consumption goal.

Primary program measures for the industrial sector, which includes electrical utilities, are projected to account for 75 percent, approximately 21 trillion Btu's, of the State's overall energy savings in 1980. Specific utility measures include primary program efforts to increase the efficiency of plant operations and secondary program activities covering utility rate reforms and utility siting for cogeneration and waste heat recovery purposes.

Major responsibilities for energy management in Wyoming are assigned to the State's Mineral Development Division, Department of Economic Planning and Development. Energy-related activities of the Division include administrating the Fuel Allocation Program under FEA, preparing energy production and consumption projections, providing technical advice to the State Energy Conservation Coordinator, and working with industry and other agencies on energy matters. Currently, the Governor's office Press Secretary serves as the State Energy Conservation Coordinator. For more information on Wyoming energy policy and programs write Mineral Development Division, Department of Economic Planning and Development, Barrett Building, Cheyenne, WY 82002.

Specific questions about the State's Energy Conservation Plan can be addressed to the Energy Conservation Coordinator, Wyoming Energy Conservation Office, Capitol Hill Office Building, 25th and Pioneer, Cheyenne, WY 82002.

State Energy Laws and Regulations

A wide variety of laws and regulations covering land use, environmental quality, and energy facility siting operate in conjunction with similar Federal requirements and controls in the 10 Missouri River Basin States. For example, State power plant siting laws complement Federal laws requiring that: (1) all nuclear power plants be licensed by the Nuclear Regulatory Commission; (2) all plants encroaching on a navigable stream obtain a permit from the U.S. Army Corps of Engineers; and (3) any power plant or transmission line must be licensed by the Federal Energy Regulatory Commission if it is located on or crosses any public land or land and water over which Congress has jurisdiction. Other Federal laws for which most States have developed (or will develop) counterpart requirements include the amended Clean Air Act of 1970, the Federal Water Pollution Control Act Amendments of 1972, the Surface Mining Control and Reclamation Act of 1977, and the Flood Plain Management Act of 1968.

The remainder of this chapter reviews existing State laws and proposed legislation covering land use, to include power plant siting and transmission line locations, controls on the extraction of energy fuels and flood plain management; and environmental quality, including air and water pollution control related to the production of electric power.

Colorado

Energy Facility Siting. The utility siting responsibility in Colorado rests with the Public Utilities Commission. This authority extends primarily to power plants, per se. The authority to regulate transmission lines rests with local government through either zoning regulations or through H.B. 1041, which enables local governments to declare transmission lines as "Areas of Statewide Concern." These authorities are not widely exercised by the Colorado counties.

Land Use Control. In 1976, the Colorado Mined Land Reclamation Act (CRS 34-32-100 et. seq.) was passed extending State jurisdiction over the mining and reclamation activities of all mining activities in the State. In 1977, the Federal Government passed the Surface Mining Control and Reclamation Act, enabling States that met certain requirements to assume primacy over coal mining reclamation. In July of 1979, the Colorado Legislature passed the Colorado Surface Mining Reclamation Act (CRS 34-33-101), meeting the minimum requirements. The State adopted the rules and regulations for this bill in August of 1980 and program approval was received from the Secretary of Interior on December 15, 1980. The bill title is somewhat of a misnomer, as its jurisdiction includes both surface and subsurface mining activities. This law allows for more public input and more specificity than is provided for with other types of mining in the State.

Inactive Mine Lands. Under the 1979 Colorado Surface Coal Mining Reclamation Act, a State program was initiated to inventory inactive mine sites and propose mitigation measures for any adverse conditions of these sites. The inventory of some 8,000 mines was completed by the Inactive Mines Program in 1980. In the 1981 Legislative Session, H.B. 1216 has been introduced which would take the Federal guidelines for dealing with inactive mines and tailor them to Colorado conditions. The program has ongoing work in the areas of hazardous opening, subsidence hazard evaluation, mine drainage, historic evaluations, and public participation.

Environmental Quality. The Colorado Department of Health's Water Quality Control Commission administers a State permit system to regulate the discharge of pollutants into any State water. All commission activities to classify State waters, develop water quality standards, and promulgate pollution control regulations comply with the requirements of the Federal Water Pollution Control Act Amendments of 1972 (P.L. 95-500) and, therefore, must include the regulation of thermal discharges from electric generating plants. The Commission is presently holding hearings on a revision of State water quality standards, which include 72 parameters.

Under the Colorado Air Pollution Control Act of 1970, as amended in 1973, the Air Pollution Control Commission of the Colorado Department of Health is responsible for requiring that all available practical methods to reduce, prevent, and control air pollution be employed. The Colorado Act also requires that a construction permit be issued when any new or substantially altered facility, except single family dwellings, constitutes a new air contamination source or an indirect air contamination source.

Colorado air pollution laws have undergone several changes since the previous report. In addition to adopting new source performance standards identical to the Federal standards, the State has adopted technology specific source standards for old and new coal-fired steam, oil-fired steam, combustion, natural gas, oil production and refining, cement manufacturing, etc. For more specific information write the Technical Secretary, Air Quality Control Commission, 4210 E. 11th Ave., Denver, CO 80220. Copies of regulations can be obtained from this address for a nominal charge.

Energy Facility Siting. Energy facility siting under Chapter 476, Iowa Code 1979, encompasses environmental quality and natural resources factors in one proceeding.

Before the construction or significant alteration of any electric power generating plant with 100 MW or greater installed nameplate capacity may begin, the Iowa State Commerce Commission must issue a certificate of public convenience, use, and necessity covering the action. Procedures involved in the issuance of the required certificate include the filing of an application and appropriate information with the Commerce Commission and the scheduling and convening of a prehearing conference, an information meeting, and a public hearing. As a result of the information obtained from the applicant and the decisional participation of agencies of the State of Iowa, such as the Iowa Department of Environmental Quality and the Iowa Natural Resources Council, the Commerce Commission decides, on the basis of statutory criteria, whether the application should be amended, denied, or approved. If requested by an applicant, the granting of a certificate may include the right of eminent domain.

An important aspect in Commerce Commission power plant siting proceeding, relates to the availability and use of water required for condenser cooling. In Iowa, the Natural Resources Council (NRC) must grant a water permit before water can be consumed for the generation of electricity. Specific water use considerations cover:

1. Surface sources (river and streams)

   Withdrawals may be permitted during those periods when the discharge of the river is above the "protected flows" established by the NRC. During periods when the discharge of the river is below the protected flow, withdrawals are permitted only if an amount of water equal to the consumptive use at the generating facility is supplied to the river from an auxiliary source such as a reservoir or other suitable source.

2. Shallow ground water sources

   Withdrawals may be permitted provided they are not:

   a) detrimental to any public interests or the interests of property owners with prior or superior rights, or

   b) detrimental to the flow in rivers or streams. (Such withdrawals would then be subject to the protected flow restrictions in 1 above).

3. Deep ground water sources

   Withdrawals from deep ground water sources are generally discouraged unless the water is of such quality as to be of little or no value for uses other than cooling. These deep formations may have slow rates of recharge and mining of water with declining piezometric levels could result from large withdrawals. In any case, condition 2a would apply.

Further, the amount of water authorized by permit and, therefore, the Commerce Commission certificate must be consistent with industry-wide usage for the same or similar purposes.

Land Use Control. The Iowa Natural Resources Council is charged with the responsibility for establishing flood plain encroachment limits and approving applications for the construction of structures to be built in the flood plain and floodway. This control extends to the power plants wishing to locate in the flood plain adjacent to a source of cooling water and to any levees or dikes necessary to protect a generating station from flooding.

Environmental Quality. The Chemicals and Water Quality Division of the Department of Environmental Quality is responsible for ensuring that thermal discharge standards, established under section 400.16 3 (3) of the Iowa Administrative Code, are not violated. The Department is also responsible for establishing acceptable water use designations for creeks, streams, and rivers in Iowa.

The Air and Land Quality Division of Iowa's Department of Environmental Quality is charged with controlling the atmospheric pollution in the State. The division requires the granting of a State permit for fossil fuel-fired steam generators.

The division also requires that such facilities obtain a State permit for all solid waste disposal facilities including ash disposal sites and ash ponds.

Kansas

Energy Facility Siting. Under K.S.A. 66-1, 158-661, and 169, dated July 1, 1976, any electric utility wishing to construct a new plant or expand an existing facility is required to obtain a permit from the State Corporation Commission. Kansas Electric Generation Facility Siting Act, Senate Bill 151, extends the Corporation Commission's responsibility considerably. For instance, prior to the commission's determination regarding the most reasonable location and size of a proposed electric generation facility or an addition to a facility, it must determine whether or not a necessity exists for the electric generation capacity of the proposed facility. In addition to several other considerations, the commission must make a determination regarding whether or not the generating capacity meets the electrical energy needs of the people of the State and in doing so must consider the probable future statewide electrical energy needs. Another major factor that must be taken into consideration is whether or not available electrical generating capacity exists within the State, and if so, whether that excess capacity can be distributed to the area for which the siting permit is being requested.

The commission is allowed to condition any permit which would be granted and to postpone its decision on any siting application if approval of other application must be obtained from any State regulatory authority before rendering its final decision. If the regulatory authority cannot issue a final approval of an application until the facility is in actual operation, the commission can accept as proof of approval or disapproval a certification of probable acceptability or unacceptability from the regulatory authority.

In making its final decision with respect to the most reasonable size and location of a power generation facility, the commission is to consider the availability of whatever natural resources are necessary for operation of the proposed facility or addition to that facility.

The "grandfather clause" which exempted any facility or addition to that facility for which construction had begun prior to July 1, 1976, or any electric utility which had acquired one-fourth of the total amount of land to be used in connection with the construction, operation and maintenance of a proposed facility or addition, is eliminated from Senate Bill 151.

Land Use Controls. K.S.A. 48-1601 to 1619, the Nuclear Energy Development and Radiation Control Act, is a statement of State policies regarding the development and utilization of sources of radiation for peaceful purposes and institution and maintenance of a regulatory program for sources of radiation to provide: (1) compatibility with the standards and regulatory programs of the Federal Government, (2) an integrated and effective system of regulation within the State, and (3) a system compatible with those of other States. The law also contains provisions (section 1604) for State agencies to conduct studies and make recommendations to the Secretary, Department of Health and Environment, regarding changes in laws and recommendations for enactment of laws or amendments to existing laws relative to nuclear and radioactive materials.

Section 1606 outlines the duties and responsibilities of the Secretary, Department of Health and Environment, in regard to State radiation control, the licensing, registration, possession and sources of radiation and records thereof; establishing procedures, rules and regulations regarding granting, suspending, revoking or amending any license; monitoring and inspection; filing injunction proceedings; manufacturing and transport; and sets forth penalties and other matters relating to the by-product and source of special nuclear materials and radiation producing devices.

Electric utilities subject to the provisions of the Siting of Electric Transmission Lines and extensions, Senate Bill 441, are required to secure a siting permit from the State Corporation Commission before beginning site preparation for or construction of an electric transmission line or before exercising the right of eminent domain in connection with preparing to construct a transmission line. The utility is required to file an application for permit which must include the location, names and addresses of landowners and other such information as the Commission may require.

Senate Bill 441 also contains provisions for a public hearing on an application and the Commission's duties in regard to determining the reasonableness of the proposed location of the transmission line and the manner in which the hearings are to be conducted.

Senate Bill 441 does not apply to any electric utility which complied with provisions of the NEPA of 1969, i.e., regarding the siting of electric transmission lines.

Minnesota

Energy Facility Siting. The Minnesota Energy Agency (MEA) is charged with certifying the need for the construction of large energy facilities. (M.S. 116H.13, 116H.07) "Large energy facilities" include electric facilities of 50 MW or greater; electric facilities of 5 MW or greater which require oil, natural gas, or natural gas liquids as a fuel; and other energy installations such as transmission lines of specified capacities and lengths, pipelines, storage and transshipment facilities, refineries, and waste conversion facilities.

The Environmental Quality Board (EQB) has the authority to issue a "Certificate of Site Compatibility" for electric power plants of 50 MW or more, and high voltage transmission lines of 200 kilovolts or greater. (M.S. 116C.53) EQB has set forth criteria for determining "preferred sites," "avoidance areas," and "exclusion areas." It is in the process of developing an inventory of study areas - areas which are judged to be suitable for the location of one or more large energy facilities. EQB is also studying the economic, environmental, and social impacts of various sized power plants, and the potential for cogeneration and production of electricity from alternative energy sources. EQB also determines whether an Environmental Impact Statement will be required. (In some cases, an EIS is required by law).

Land Use Controls. Minnesota energy-related land use controls have been applicable mainly to electric power production and pipelines and transmission lines, since energy-related mining or production has not occurred in the past. However, a recent interest in peat and uranium mining has led to evaluation of impacts and of the ability of the State regulatory framework to deal with these impacts.

The Minnesota Department of Natural Resources (DNR) has been studying potential (energy and nonenergy) uses of peat and potential impacts of development. DNR has presented to the 1981 Legislature a series of peat management policy recommendations. Among the recommendations is the inclusion of peat mining under the reclamation statutes.

The 1980 Minnesota Legislature passed a law regulating exploratory drilling for uranium. The law requires the reporting of certain exploratory data to the DNR and regulates the construction and abandonment of exploration wells through the Minnesota Department of Health. The State's Department of Natural Resources and Environmental Quality Board are currently assessing the State's statutory authority to manage uranium mining.

The Minnesota Department of Natural Resources oversees the State's water appropriation permit process as defined in M.S. 105.41. Water appropriators using more than 10,000 gallons per day or 1 million gallons per year are required to obtain a permit. Permit rulings are subject to the priority system as well as to instream flow protection and well interference considerations.

Control over the use of land in the flood plain is the responsibility of the State's Department of Natural Resources, as assigned under the Flood Plain Management Act, (M.S. 104.01 to 104.07). DNR also has authority over shoreland protection, under the Shoreland Management Act (M.S. 105.485). Both of these programs are implemented at the local level of government.

Environmental Quality. Efforts to control the effects of power plant thermal discharge are designated responsibility of the Minnesota Pollution Control Act (M.S. 115.01-115.09) MPCA also is responsible for State air quality maintenance and manages a permit program for air pollutant discharges.

The Environmental Quality Board serves as a discussion, policymaking, and conflict resolution body on environmental issues which are interdepartmental in nature.

Land Use Control. Missouri's Land Reclamation Law became effective in March 1972. Prior to the act becoming effective, the Missouri Legislature created a Land Reclamation Commission in 1971 to enforce the pending law. Under recent reorganization, responsibility for the land reclamation program was placed within the Missouri Department of Natural Resources (DNR). The commission is still responsible, however, for establishing the reclamation policies to be carried out by DNR. Under the law, industries mining coal (or other minerals) must obtain a permit to surface mine. The permits are issued for only a specific number of acres. Further, a performance bond is required for any acreage covered by permit to insure that land reclamation will be completed. Each company mining coal is also required to submit a comprehensive water management plan explaining what provision will be made to control erosion and runoff. Other land use regulations are defined by Missouri Riparian law of reasonable use and laws affecting hazardous waste.

Environmental Quality. The Missouri Clean Water Act was passed in 1972. Under the law, the Clean Water Commission establishes State water quality policy, which is then implemented by DNR. Based on the present State water quality standards covering temperature, thermal effluents may not elevate or depress the temperature of the stream more than 5$0^{\circ}$ F. In addition, the stream temperature shall not exceed 9$0^{\circ}$ F due to effluents. For reach of streams designed for stocking or propagation of trout, the temperature shall not be elevated more than 2° F due to effluents. No activity of man shall cause reaches of streams used for stocking or propagation of trout to exceed 6$8^{\circ}$ F. Additionally, no elevation in the temperature of lakes shall be due to effluents. (The standards recognize that Lake Springfield and Thomas Hill Reservoir were constructed especially to provide industrial cooling water, and so will have a mixing zone of heated water.) Additional control over effluent discharge problems is provided by the State's participation in the NPDES permit program.

The Missouri Air Conservation Commission, established by the State's 1965 Air Conservation Law, is charged with preventing, abating, and controlling air pollution. Policies and regulations resulting from Commission action are implemented by the DNR. In addition to controlling the firms already established in Missouri, the commission controls new firms and activities locating in the State. Prior to the construction of any new air contaminant source or modifications to existing sources, firms must first obtain a permit for construction from DNR. New source performance regulations recently issued by the Air Conservation Commission cover 12 source categories including power plants.

Montana

Energy Facility Siting. The Major Facility Siting Act, enacted in 1973, provides for comprehensive review of proposals to construct and operate certain kinds of facilities for generating, converting or transmitting energy in Montana. The legislature found that additional facilities may be required to meet an increasing demand for electricity and other forms of energy, but that such facilities have major impacts on the environment, on population distribution, and on the welfare of the citizenry. To minimize adverse impacts, the Board of Natural Resources and Conservation must certify public need for and environmental compatibility of such facilities before construction begins. Air and water quality related matters are the responsibility of the Board of Health and Environmental Sciences.

The act applies to: (1) facilities that can generate 50 MW or more of electricity; (2) facilities that can produce 25 million cubic feet or more of gas per day; (3) facilities that can produce 25,000 barrels of liquid hydrocarbon products per day; (4) uranium enrichment facilities; (5) facilities that can use, refine, or convert 500,000 tons of coal or more per year; (6) electric transmission lines greater than 69 kv capacity, with certain exceptions for lines covering short distances; (7) facilities for developing and using geothermal resources capable of producing 25 million Btu's per hour or more; (8) facilities for <u>in-situ</u> coal gasification; and (9) pipelines leading from or to a facility as defined above. Facilities under exclusive Federal jurisdiction are exempt.

Applications for facilities filed under the act must include a description of the proposed facility, with discussion of alternative sites, an explanation of need for a utility facility, discussion of efforts to promote conservation and reasonable alternative energy sources and a filing fee, based on the estimated construction cost of the facility, to finance the State's evaluation.

The 1979 Legislature amended a number of substantive and procedural sections of the Major Facility Siting Act (MFSA) in order to clarify the schedule the State must follow in evaluating and reaching a decision on applications. Particular attention was given to the jurisdictions of DNRC and the Department of Health and Environmental Sciences (DHES). Applicants are now required to file a joint application with both departments for a certificate of environmental compatibility and public need and for the permits required by state air and water quality laws. Both deparments must accept an application as complete before the evaluation process begins.

Within one year after accepting an application, DHES, and the Board of Health, if applicable, within an additional six months, must issue a decision with regard to State and Federal air and water quality laws. Compliance with air and water quality standards must be determined for primary and reasonable alternate locations for a proposed facility.

DHES's or the Board of Health's decision is conclusive on all air and water quality matters. The Board of Natural Resources retains the authority to determine that a site represents the minimum adverse environmental impact, and DNRC retains responsibility for evaluating impacts of altered air and water quality on terrestrial and aquatic environments. DNRC has 22 months following acceptance of an application for an energy conversion facility or major transmission line, rather than the 24 months previously allotted, to report to the Board. The time limit for DNRC's review and report for transmission lines under 30 miles long is one year.

An application may not be filed unless the facility is identified in a long range plan submitted to DNRC at least two years before DNRC accepts the application.

Applicants are required to submit baseline data for the preferred and reasonable alternate site locations identified in an application. At the applicant's option, an environmental study plan may also be submitted. DNRC may allow a credit against the required filing fee for information provided by the applicant, if it is valid and useful for preparing an environmental impact statement. With 30 days notice, the credit may be reduced any time the DNRC needs the funds to carry out its responsibilities. DNRC may also contract with an applicant to provide

information. Payments to DNRC must be credited against the filing fee and the fee must be sufficient to permit the department, board, and other affected agencies to carry out their responsibilities. If there is no contract, applicants must pay the fee in installments according to a schedule developed by DNRC, and no one installment may exceed 20 percent of the total fee. Applicants are entitled to a refund with interest at 6 percent per year of any portion of the fee that remains after all procedures associated with facility certification have been completed.

The 1979 Legislature assigned specific time limitations to most phases of the hearing process. The entire process, from the date of the Department's report to the Board until the hearing examiner's report is filed, shall not exceed nine months unless the Board extends the time for good cause. The board must make its decision within 60 days after the hearing examiner's report is submitted.

A certificate may not be granted unless the board finds and determines: (1) the nature of the probable environmental impact; (2) that the facility represents the minimum adverse environmental impact, considering the state of available technology and the economics of various alternatives; (3) that the facility is consistent with regional plans for expanding utility grids and will serve system economy and reliability; (4) that the facility's proposed location conforms to State and local laws and regulations; (5) that the Board of Health has certified that the facility will not violate air and water quality standards and implementation plans; and (6) for a utility application, that the facility serves the public interest, convenience and necessity. Need, environmental impact, benefits to the applicant and the State, effects of resulting economic activity, and effects on public health, safety and welfare must be considered in making these determinations.

An initiative passed in 1978 amended the MFSA to require the Board of Natural Resources and Conservation to find that a number of conditions are met before a nuclear power plant may be certified. The voters of the State must then approve the facility either by referendum or initiative.

The MFSA requires annual submission of long-range plans by utilities and any person contemplating construction of a facility within the ensuing ten years. The plans must also be filed with the Public Service Commission, EQC, DHES, and the Departments of State Lands, Highways, and Community Affairs.

Certificates may be revoked for failure to meet safety standards or failure to comply with any other conditions imposed by the board. Penalties up to $10,000 per day may also be assessed. DNRC is responsible for monitoring the operation of facilities.

The 1979 Legislature amended the MFSA with respect to applications and certificates. Applicants are required to supplement an application as requested by DNRC, and DNRC may determine that the supplemental information requires an amendment to an application at any time before DNRC's final recommendation. Additional filing fees or a new application may be required as the department determines necessary to carry out its responsibilities. If an applicant wishes to amend a certificate DNRC has 30 days to determine whether the proposed change would materially increase any environmental impact or substantially change the location of all or a portion of the facility. If the Department determines that there would be a material increase in impact or substantial change in location, the board must hold a hearing and then render a decision; otherwise the board must automatically grant the amendment, as proposed or with conditions.

Land Use Control. Passed in 1974 and amended in 1975, the Strip and Underground Mine Siting Act, (Section 82-4-101 et seq. MCA), applies to coal and uranium mines and establishes a State policy "to provide adequate remedies for the protection of the environmental life support systems from degradation and provide adequate remedies to prevent unreasonable depletion and degradation of natural resources."

The act applies to any mining operation removing more than 10,000 cubic yards of mineral or overburden per year. A mine site location permit must be secured from Department of State Lands (DSL) before any preparatory work is begun, including all onsite disturbances (except prospecting) such as railroad building and transmission line construction and erection of draglines and loading shovels. Within one year of receiving a complete application, DSL must notify the applicant if the application is acceptable, in which case a one year permit is issued. The permit is renewable until a permit is secured under the Strip and Underground Mine Reclamation Act. DSL may not issue a permit if it finds that: (1) the proposed mine violates the purposes of the act; (2) the area could not be approved under the selective denial criteria of the reclamation act (Section 82-4-201 et seq. MCA); or (3) reclamation plans do not meet the requirements of the reclamation act. Content of the application for a mine site location is specified in the regulations. Each application must include a reclamation plan.

Before a permit is issued, the applicant must post a surety bond of between \$200 to \$10,000 per acre unless the actual reclamation cost is higher. Forfeiture of a bond means an operator is ineligible for future permits unless the site is reclaimed without cost to the state. All fees and forfeit bonds are credited to a mining and reclamation fund and are spent, by appropriation, for administering and enforcing the act and for reclamation of land and water.

In the event of violations, all permits held by the operator are suspended and no further permits will be issued if violations are repeated. Additionally, the operator is liable for civil penalties or misdemeanors for willful violations. The latter incur a fine of between \$500 and \$5,000 per violation per day.

Any resident who knows the act or DSL regulations are not being enforced must first request an enforcement action, but then may sue the responsible State officer, if necessary, to compel him or her to enforce the provisions.

The Strip and Underground Mine Reclamation Act, (Section 82-4-201 et seq. MCA), passed in 1973 and revised extensively in 1979, applies to coal and uranium strip and underground prospecting and mining operations that remove more than 10,000 cubic yards of mineral or overburden per year. The Board of Land Commissioners and the Department of State Lands (DSL) administer the law.

The reclamation law declares it is "the policy of this State and its people: (1) to maintain and improve the State's clean and healthful environment for present and future generations, (2) to protect its environmental life support system from degradation, (3) to prevent unreasonable degradation of its natural resources, (4) to restore, enhance, and preserve its scenic, historic, archeologic, scientific, cultural and recreational sites, (5) to demand effective reclamation of all lands disturbed by the taking of natural resources, and (6) to require the legislature to provide for proper administration and enforcement ... in order to achieve the aforementioned objectives." The Legislature found it necessary to require permits for mining operations, a comprehensive plan for reclamation and an adequate performance bond, and to prohibit mining on certain land.

A one-year permit must be secured from DSL before any exploratory work may begin. A perspective map, reclamation plan and description of prospecting techniques must be submitted and a reclamation bond must be posted.

Before mining begins, a five-year permit, contingent on an acceptable reclamation plan for the affected land, vegetation and water, must be secured. A bond is also required to cover actual reclamation costs. The permit application must include written consent or waiver by the surface owner(s) of the proposed mining area.

According to the law, DSL may not approve a mine application if: (1) any part of the proposed operation would be contrary to the purpose of the act; (2) the proposed site or neighboring area includes land having special, exceptional, critical or unique characteristics--defined as (a) biological productivity essential to certain wildlife species or domestic stock, (b) ecological fragility, in the sense that the land could not return to its former ecological role in the reasonably foreseeable future, (c) ecological importance, in the sense that mining could precipitate a system-wide reaction of unpredictable scope, and (d) scenic, historic, archaeologic, topographic, geologic, ethnologic, scientific, cultural or recreational significance, with particular attention to Plains Indian history and culture), (3) the overburden on any part of the areas has historically proven to be a problem in terms of landslides or various forms of water pollution (DSL shall delete that area from the mining plan); and (4) the operation constitutes a hazard to a personal dwelling or public property (such areas shall be deleted).

The mining operation must begin reclamation "as rapidly, completely and effectively as the most modern technology and the most advanced state of the art will allow." The law requires specific actions and includes technical requirements for backfilling, grading and topsoil replacement. The operator is required to submit annual progress reports, but may propose alternatives in the process if they are consistent with the intent of the act. DSL may order appropriate changes.

All fees, forfeit funds and other money collected under the act are put in the mining and reclamation fund for administering and enforcing the act and for reclamation.

The act provides several types of legal recourse against violations, including: (1) State suits against the mine operator for civil penalties of between $100 and $5,000 per violation per day; (2) a misdemeanor for willful violation carrying a $500- to $10,000-per-day penalty; (3) a resident's suit against a public official to compel him or her to enforce any provision being violated; and (4) a suit for damage against the operator by an owner of real property whose use of underground water is impaired.

Several changes in the law were made by the 1979 Legislature to comply with the Federal Surface Mining Control Act of 1977. These changes included more stringent civil penalties for violations, authorization for designating lands unsuitable for mining process, and restrictions on mining in certain alluvial valley floors. The law was also changed to allow revegetation to cropland or pastures as an alternative to predominantly native species.

Environmental Quality. The Montana Water Quality Act (section 75-5-101) defined Montana's public policy to conserve water and protecting, maintaining and improving the quality and potability of water for public water supplies, wildlife, fish and aquatic life, agriculture industry, recreation and other beneficial uses. (Note: coal slurry is specifically excluded as a beneficial use of water in Montana.) The act also called for the provision of a comprehensive program for the prevention, abatement and control of water pollution.

The Montana Water Pollution Law permits the State Department of Health and Environmental Sciences to establish and modify the classifications of all waters in accordance with their present and future beneficial use, to establish water purity standards, to regulate discharges to State waters through a permit system, to monitor discharges and water quality, and to enforce the established standards. At present, thermal discharge standards have been established by water use classification for all State waters (MAC 16-2.14 (10) - S14480).

The Montana Clean Air Act permits the State to establish, monitor, and enforce emission and ambient air standards. The act also prohibits the construction, installation, alteration, or use of any machine, equipment, device or facility that may directly or indirectly cause or contribute to air pollution or that is intended primarily to prevent or control the emissions of air pollutants unless a permit is first obtained. Fuel burning equipment limitations for particulates, visible air contaminants, sulfur oxide emissions, and ambient air quality standards are contained in the Montana Administrative Code as sections 16-2.14 (1) S1450, 16-2.14 (1) S1460, 16-2.14 (1) S1470, and 16-2.14 (1) S14040, respectively.

Nebraska

Energy Facility Siting. Nebraska does not have a utility siting statute. The State does, however, have a permit and licensing law affecting transmission lines for power plants. Nebraska is unique in that all electric utilities serving the State are public entities organized under appropriate statutes and as such are subject to statutes regulating political subdivisions of the State. They are controlled by boards of directors elected by the public or in the case of a municipality, the city council. In addition, the operation of these facilities are subject to regulation by the Power Review Board.

The Power Review Board has statutory power to authorize or deny the construction of transmission lines and related facilities outside the corporate units of cities and villages. It also has the authority to require public power districts, municipalities, and other wholesale and retail power suppliers to enter into service area agreements, to establish service area boundaries and to settle disputes arising between utilities, and between customers and utilities.

The use of surface water is controlled primarily by a statutory system providing for the appropriation of water for beneficial purposes, including the production of electric power. A number of court decisions, however, still recognize the validity of some limited riparian rights. Under Nebraska's appropriation system, rights to the use of surface water are based on appropriation to a beneficial use, first in time being first in right, subject to the approval and regulation of the

Department of Water Resources. In addition, an appropriator using water for power purposes must appropriate the water from the State through the Department of Water Resources. When the water supply in the stream is insufficient to satisfy the needs of all appropriators, preference is given to different uses of water as follows: (2) domestic, (2) agricultural, and (3) manufacturing. A junior appropriator, however, may only take water for power purposes if just compensation is paid.

Use of ground water for power production is subject only to general restrictions on wells. All wells, including those for manufacturing and industrial use, must be registered with the Department of Water Resources and are subject to certain restrictions on spacing from adjacent wells. As in the case of surface water, industrial wells are given third priority in the preference system. Recently enacted statutes provide a system for establishing more restrictive controls in specially designated control areas with severe ground water problems. These control areas, administered by natural resources districts, could place more severe restrictions on the use of ground water for power production, but there has been no experience with such a system to date.

Environmental Quality. All power plants owned and operated by a public district or municipality are subject to the rules and regulations of the Nebraska Department of Environmental Control and appropriate Federal agencies. The Department of Environmental Control acts as the State's air and water pollution control agency and is empowered to enforce air and water quality standards in the State.

Legislation. Nebraska has a vital interest in the development of Great Plains coal. Even though coal reserves are not found within the State, the mining of coal in other areas can have serious effects on water depletions. Other secondary effects can also be experienced.

There is growing concern in Nebraska regarding the use of ground water by large industrial users, including power plants. A proposed coal slurry pipeline and power plant have triggered some activity in this area. Legislation enacted in 1981, under the title Industrial Ground Water Regulatory Act, requires State approval by way of a permit system before a large industrial user can withdraw 3,000 acre-feet or more of ground water per year. Power generation is included as an industrial purpose under the act. The legislation would protect the priority of existing users of ground water, recognizing that domestic use currently holds the highest priority, followed in order by agricultural use and industrial use. Legislation has been proposed which would require preparation of a 20-year power supply plan for Nebraska's electric industry and which would modify some aspects of public power laws. The latter piece of legislation would transfer to the Power Review Board the responsibility for approving the creation of any public power district and the sale, lease, or transfer of any electric light and power plant, distribution system or transmission lines. Such authority currently rests with the Department of Water Resources. Utility siting and certificate-of-need legislation are also anticipated.

There is a developing controversy surrounding recent uranium exploration in the State. Legislation has been proposed which would protect the ground and surface water from pollution from uranium mining and require the restoration of any land disturbed by mining operations. The Nebraska Legislature has not enacted legislation to permit the use of eminent domain for slurry pipelines. There has been some concern that such legislation would set a precedent and cause the transport of vast amounts of water to other areas of the country.

North Dakota

Energy Facility Siting. North Dakota law pertaining to utility siting and permit or licensing activities is found in Chapter 49-22 of the State's Century Code. Changes made to these laws since 1977 are limited to refinements in the wording and organization of some sections. There has been essentially no change in either the intent or objective of these laws. The State agency with authority in this area is the Public Service Commission (PSC). The Public Utility and Siting Division of the PSC is directed by the Chief Engineer located in the Capitol Building, Bismarck, North Dakota.

The North Dakota State Water Commission has recently agreed to handle the DOE Small-Scale Hydroelectric Power program for the State of North Dakota. The purpose of the small-scale hydroelectric power program is to encourage municipalities, electric cooperatives, industrial development agencies, nonprofit organizations, and other persons to undertake the development of small hydroelectric power in connection with existing dams which are not currently being used to generate electric power. The DOE program provides loans of up to 90 percent or $50,000 maximum for a potential small-scale hydropower developer to conduct either a feasibility study of a site or to carry out the licensing procedure that may be required to construct the project. The program applies to existing dams built prior to April 20, 1977, which are not currently being used for power generation and whose potential generating capacity lies between 100 kW and 30 MW.

The State Water Commission will assist the DOE by performing the following duties: promoting small-scale hydroelectric power development, examining potential sites, and conveying program benfits to site owners.

There are nine dams located in the Missouri Basin of North Dakota that could potentially generate small-scale hydroelectric power.

Potential Sites	County
Blacktail Dam	Williams
Epping Dam	Williams
Lake Ilo	Dunn
Patterson Lake	Stark
Heart Butte Dam	Grant
Square Butte #4	Oliver
Nelson Lake	Oliver
Sweetbriar Dam	Morton
Smishck Dam	Burke

Land Use Controls. North Dakota's Reclamation of Strip Mined Lands Act expresses the Legislature's intent:

> To provide, after surface mining operations are completed, for reclamation of affected lands to encourage productive use including but not limited to: the planting of forests; the seeding of grasses and legumes for grazing purposes; the planting of crops for harvest; the enhancement of wildlife and aquatic resources; the establishment or recreational, home, and industrial sites and for the conservation,

development, management, and appropriate use of all of the natural resources of such areas of compatible multiple purposes; to aid in maintaining or improving the tax base; and protecting the health, safety, and general welfare of the people, as well as the natural beauty and esthetic values, in the affected areas of this State.

It is also intended that reclamation practices required by this act restore mined lands designated for agricultural purposes to the level of inherent productivity equal to or greater than that which existed in the permit area prior to mining (38-14 of the North Dakota Century Code, Chapter 318 of North Dakota Session Laws, 1975). Other stipulations in the law cover requirements for public hearings, establishment of standards, issuance of permits and provisions for penalty.

State law relating to reclamation of mined lands underwent major revisions in the 1979 State Legislature. New chapters in the law bring North Dakota's regulations more into line with those of the Federal Government. Chapters 38-14.1 and 38-14.2 replace Chapter 38-14. These laws deal with reclamation of distrubed land in active mining operations and at abandoned mine sites. Chapter 38-18 assures the surface owner of reclamation by the mineral developer. North Dakota reclamation laws are administered by the Public Service Commission's Reclamation Division located in the State Capitol Building, Bismarck, North Dakota.

Environmental Quality. Chapter 61-28 of North Dakota's Century Code contains measures dealing with control, prevention, and abatement of pollution of the State's surface waters. This chapter gives the State the authority to adopt, amend, or repeal rules, regulations, and standards for water quality, and it provides for penalties for violations thereof. Standards for water quality have been established by the State Department of Health which include specifications for thermal pollution limitations. No substantive change has occurred in the intent and objectives of sections of this chapter since 1977. The Water Supply and Pollution Control Division of the State Department of Health has major responsibility in the area of water quality protection. These offices are located at 1200 Missouri Avenue, Bismarck, North Dakota.

Air pollution control legislation is found in chapters 23-25 of the North Dakota Century Code. No substantive changes have been made in these laws since 1977, with the exception of the establishment of a fee system to compensate the State for costs in the review and issuance of permits or registration certificates. The State Department of Health has authority in air quality regulation. The Department's Environmental Engineering Division exercises direct responsibilities and is located at 1200 Missouri Avenue, Bismarck, North Dakota.

The State of North Dakota historically has been very cautious with development of its water resources. State law declares all water in the State to be the property of the public. Administrative management of the resource is accomplished, in part, through careful appropriation of water rights. A water right must be obtained by anyone prior to withdrawal or storage of water within specified criteria. Extensive analysis is made of each water right application to ensure that the proposed use is compatible with the natural water system. Restrictions may be, and often are, placed upon a water right appropriation to ensure efficient use and to protect the resource for existing and potential appropriators. With anticipated growth in demand on water resources from industry, agriculture, and increased population, the State will continue to emphasize conservation and look for ways to distribute available supplies to areas with demonstrated needs.

South Dakota

Energy Facility Siting. Chapter 49-41B of the South Dakota State Code, known as the Energy Facility Permit Act, relates specifically to the State's permit and licensing procedures for energy conversion and transmission facilities. All provisions of the law relevant to both large and small energy facilities are administered by the South Dakota Public Utilities Commission. While the law does not delegate to the commission the authority to route a transmission line or to designate or mandate the location of an energy conversion facility, it does require that the proposed facility not pose a serious injury to the environment and the social and economic condition of the area or substantially impair the health, safety, and welfare of the area's inhabitants if a construction permit is to be granted.

Land Use Control. Regulations covering surface mining activities are administered by the South Dakota State Conservation Commission. The commission is also responsible for controlling water quality problems caused by erosion.

Wyoming

Energy Facility Siting. The State Industrial Siting Council is assigned the responsibility of regulating the siting of energy and conversion facilities under the Wyoming Industrial Development and Siting Act. Under Wyoming Statute 35-12-101 to 121, three types of plants are required to be authorized by a permit issued by the council: energy generating or conversion plants capable of generating 100 MW or greater of electricity; facilities producing 100 million cubic feet of synthetic gas per day, 50,000 or more barrels of oil per day, or enriching 500 or more pounds of uranium per day, or plants with an estimated cost of $50 million or more before being developed. All pertinent factors, including environmental and socioeconomic impacts, are taken into account before the issuance of a permit. The permitting procedure also provides for the conduct of public hearings near the vicinity of the proposed facility.

Regulatory jurisdiction over public utilities is the responsibility of the Wyoming Public Service Commission (PSC). Under Wyoming Statute 37-2-205, the commission must issue a certificate of public convenience and necessity before the construction or extension of a line, plant, or system can be undertaken.

The administration of water use in Wyoming is based on a State constitutional provision that the waters of all natural streams, springs, lakes, or other collections of still water within the boundaries of the State are declared to be the property of the State. Therefore, the acquisition of the water rights that would be required for any energy development would have to be made in accordance with Wyoming Statute 41-1-101 to 41-14-103. Specifically, section 41-3-930 applies to appropriation of underground water and section 41-201 applies to surface water appropriation. In addition, State water use legislation specifies procedures for filing an application, establishment of proof of beneficial use, and the subsequent adjudication of water rights.

Land Use Control. The State of Wyoming has established a mechanism to coordinate State land use-related problems. The responsibility for this has been delegated to the Wyoming Department of Economic Planning and Development. Further, the State requires local governments to establish a mechanism for land use planning. The State has also adopted rules and regulations covering surface mining and the application of land reclamation measures.

Environmental Quality. The Wyoming Environmental Quality Act of 1973 (WS 11-201 to 1104) establishes the criteria for standards to be maintained and procedures of administration of air, land, and water quality in the State. The basic concept of the law is that no person, except when authorized by permit, shall cause, threaten, or allow the discharge of any pollution or waste into any waters of the State. Similar concepts apply to air and land quality control.

GLOSSARY

alluvial valley. A valley along a river, stream or lake of clay, silt, sand, gravel, rock fragments or similar loose material deposited by running water.

alternative coal technologies. Processes whereby coal is converted to either oil or gas instead of merely being mined and used as coal.

CFR. Code of Federal Regulations.

fugitive dust. Dust suspended in the atmosphere usually generated by activities such as wind, vehicle or equipment operation or blasting.

gasification. Refers to the conversion of coal to a gas fuel.

high Btu gasification. The process of converting coal to an equivalent of natural gas, predominantly methane; energy content is usually 950-1,000 Btu's per cubic foot.

low Btu gasification. The process of converting coal to gas, obtained by partial combustion of coal; energy content is usually 100 to 200 Btu's per cubic foot.

liquefaction. The process by which gas is converted from the gaseous to the liquid phase.

Btu (British thermal unit). The amount of energy necessary to raise the temperature of one pound of water by 1° F, from 39.2° to 40.2° F.

bituminous. An intermediate quality coal, a high percentage of volatile matter, and a low percentage of moisture.

subbituminous. A low quality coal with low fixed carbon and high percentages of volatile matter and moisture.

lignite. The lowest quality coal, with low heat content and fixed carbon, and high percentages of volatile matter and moisture; an early stage in coal formation.

high-cost gas. High cost natural gas produced from any well below 15,000 feet the surface drilling of which began on or after February 19, 1977.

hydropower. Production of electricity that uses falling water as the force to drive turbine-generators.

in-situ. Occurring in place as in in-site coal gasification, where gasification occurs before the coal is removed from the ground.

leachate. A liquid containing desolved minerals and chemicals created when percolating water is passed through soil or overburden.

low-head hydro. Refers generally to those dam sites less than (60 feet or) 20 meters in vertical height and producing or capable of producing less than 15,000 kilowatts.

interties. A transmission line connection permitting a flow of energy between the transmission facilities of two electric supply systems. The flow of energy may be in either direction.

load shedding. Systematic method of dropping electric power from a system.

low sulfur coal. A solid, combustible organic material; coal with a sulfur content generally below one percent.

new gas. Natural gas produced from a new lease on the outer continential shelf, new on shore wells, any new well which is 2.5 miles or more from the nearest marker well, a new well at least 1,000 feet deeper from each marker well within 2.5 miles.

nuclear power. Energy released from the heat liberated by a nuclear reaction (fission or fusion) or by radioactive decay and converted to electric power by a turbine-generator unit.

peak load. The greatest amount (maximum) of all of the power load on a system which has occurred at one specified time.

point source. A stationary emmitting point of a pollutant, e.g., stack or a discharge pipe.

quad. Quadrillion Btu of energy.

spinning reserve. Generating capacity operating at no load or at partial load with excess capacity available to support additional load.

voltage. The electrical potential difference between conductors.

watts. Practical unit of electric power.

> **gigawatt (GW).** One million kilowatts, or one billion watts.
>
> **gigawatthour (GWh).**
>
> **kilovolt (kv).** One thousand volts.
>
> **kilowatt (kW).** One thousand watts.
>
> **kilowatthour (kWh).**
>
> **megawatt (MW).** One thousand kilowatts, or one million watts.
>
> **megawatthour (MWH).**

APPENDIX I

BULK POWER SUPPLIERS AND JOINT PLANNING ORGANIZATION SERVING THE MISSOURI RIVER BASIN

Interstate and intrastate organizations conduct individual and joint power planning throughout a large portion of the Missouri River Basin. A detailed listing of member composition and the specific functions and activities of each of the associations is presented in this appendix.

NATIONAL RELIABILITY REGIONAL COUNCILS

Mid-Continent Area Reliability Coordination Agreement (MARCA)

The Mid-Continent Area Reliability Coordination Agreement covers the major electric utilities engaged in bulk power supply within one-fourth of Montana, the western one-half of Wisconsin, all South Dakota except the Black Hills region, and all of the States of Nebraska, North Dakota, Iowa, and Minnesota. The agreement exists to increase reliability of the area's bulk power supply and coordination of the planning and operation of electric facilities in the region.

MARCA is comprised of 28 members (asterisk denotes service operation within the Missouri River Basin) as follows:

*Basin Electric Power Cooperative
*Cooperative Power Association
Dairyland Power Cooperative
Eastern Iowa Light and Power Cooperative
Heartland Consumers Power District
*Interstate Power Company
*Iowa Electric Light and Power Cooperative
*Central Iowa Power Cooperative
*Iowa-Illinois Gas and Electric Company
*Iowa Power and Light Company
*Iowa Public Service Company
*Corn Belt Power Cooperative
*Iowa Southern Utilities Company
Lake Superior District Power Company
*Lincoln Electric System
Minnesota Power and Light Company
*Minnesota Power Cooperative, Inc.
*Missouri Basin Municipal Power Agency
*Montana-Dakota Utilities Company
Muscatine Power and Water
*Nebraska Public Power District
*Northern States Power Company
Northwest Iowa Power Cooperative
*Northwestern Public Service Company
*Omaha Public Power District
*Otter Tail Power Company
*United Power Association
*Western Area Power Administration - Billings Area

Western Systems Coordination Council (WSCC)

WSCC is a voluntary council open to all bulk power suppliers in 13 Western States and the Canadian province of British Columbia. The purpose of the council is to promote reliable operation of interconnected bulk power systems. All planning for future generation and transmission facilities is the responsibility of the individual member systems and the joint planning groups with which they may be associated. However, before making final commitments for construction, such planning is reported to the WSCC, which conducts studies to determine the effect of planned changes on the reliability of the entire Western regional bulk power network.

Several subcommittees assisted the Council. The Planning Coordination Committee accumulates data and performs regional studies of the interconnected systems to determine the electrical stability and associated reliability of the regional bulk power network. It then formulates reports and recommendations based on these studies. The Operations Committee reviews and analyzes operating procedures and problems relating to the reliability of the operation of the interconnected bulk power systems, and recommends new or modified operating policies and procedures for the guidance of the member utilities. The Environmental Committee is responsible for recommending criteria, guidelines, and objectives that will help member systems achieve goals of electric power reliability and environmental compatibility. The committee includes member system representatives and nonutility members including conservationists, educators, and other contributors.

WSCC is comprised of 47 member systems and 14 affiliate members (asterisk denotes service within the Missouri River Basin) as follows:

Arizona Electric Power Cooperative, Inc.
Arizona Power Authority
Arizona Public Service Company
*Black Hills Power and Light Company
*Bonneville Power Administration
British Columbia Hydro and Power Authority
Calgary Power, Ltd.
Colorado Springs, City of
Colorado-Ute Electric Association, Inc.
Corps of Engineers (North Pacific Division)
Department of Water Resources/California
El Paso Electric Company
Eugene Water and Electric Board
Glendale Public Service Department
Idaho Power Company
Los Angeles Department of Water and Power
Metropolitan Water District/Souther.. California
*Montana Power Company, The
Nevada Power Company
Pacific Gas and Electric Company
*Pacific Power and Light Company
Pasadena, City of
Plains Electric Generation and Transmission Cooperative, Inc.
*Platte River Power Authority
Portland General Electric Company
*Public Service Company of Colorado
Public Service Company of New Mexico
PUD No. 1 of Chelan County
PUD No. 1 of Cowlitz County
PUD No. 1 of Douglas County
PUD of Grant County
Puget Sound Power and Light Company
Sacramento Municipal Utility District
Salt River Project
San Diego Gas and Electric Company
(Lower Missouri)
(Mid-Pacific)
(Pacific-Northwest)
(Southwest)
(Upper Colorado)
(Upper Missouri)
Seattle Department of Lighting (Seattle City Light)
Sierra Pacific Power Company
Southern California Edison Company
So. Colorado Power Division, Central Telephone and Utilities Corp.
Tacoma Department of Public Utilities (Tacoma City Light)
*Tri-State G & T Association, Inc.
Tucson Electric Power Company
Utah Power and Light Company
Washington Water Power Company, The
*Water and Power Resources Service
(Denver Federal Center)
(Lower Colorado)
West Kootenay Power and Light Company
Western Area Power and Administration
(Golden, Colorado)
(Boulder City, Nevada)
(Denver, Colorado)
(Sacramento, California)
(Salt Lake City, Utah)
(Billings, Montana)

AFFILIATE MEMBERS

Anaheim, City of
Bountiful City Light and Power
Electrical District No. 2,
  Coolidge, Arizona
Garkane Power Association, Inc.
Lamar Utilities Board (City of
  Lamar)
Lodi, City of
Navajo Tribal Utility Authority
Northern California Power Agency
Palo Alto, City of
PUD of Clark County, Vancover,
  Washington
Redding, City of
Riverside, City of
St. George, City of
Santa Clara, City of

Southwest Power Pool (SPP)

The Southwest Power Pool is a regional coordinating council consisting of members which operate partially or wholly within the Missouri River Basin. The SPP, as one of the nine coordinating groups of the National Electric Reliability Council, performs coordinating and planning functions on a regional basis.

Members of SPP are listed below (asterisk denotes service operation within the Missouri River Basin) as follows:

SPP - GROUP A

Arkansas Electric Cooperative
  Corporation
Cajun Electric Power Cooperative,
  Inc.
Central Louisiana Electric Company,
  Inc.
Gulf States Utilities Company
Middle South Utilities, Inc.
  Arkansas Power and Light Company
  Arkansas-Missouri Power Company
  Louisiana Power and Light Company
  Mississippi Power and Light Company
  New Orleans Public Service, Inc.
City of Ruston, Louisiana
Greenwood Utilities

SPP - GROUP B

Grand River Dam Authority
Oklahoma Gas and Electric Company
Public Service Company of Oklahoma
Southwestern Electric Power Company
Southwestern Power Administration
Southwestern Public Service Company
Western Farmers Electric Cooperative

SPP - GROUP C

*Board of Public Utilities, Kansas City,
  Kansas
*Central Kansas Power Company, Inc.
Chanute Municipal Utilities
Coffeyville Municipal Water and Light
  Department
*City Power and Light, Independence,
  Missouri
*The Empire District Electric Company
*Kansas City Power and Light Company
*Kansas Gas and Electric Company
The Kansas Power and Light Company
*Missouri Public Service Company
*St. Joseph Light and Power Company
*Sunflower Electric Cooperative
Winfield Municipal Light and Water
*Western Power Division - Central
  Telephone and Utilities Corp.

SPP - GROUP D

*City Utilities, Springfield, Missouri

Associated Electric Cooperative has membership in both MAIN and the Southwest Power Pool (SPP); agreement has been reached for Associated to report through MAIN.

The Mid-America Interpool Network (MAIN) Organization

The Mid-America Interpool Network (MAIN) was formally organized in November 1964 to promote maximum coordination of planning, construction, and utilization of generation and transmission facilities of its members in order to improve the reliability of electric bulk power supply in the Middle West.

Regular membership is open to any power supplier who has a high capacity interconnection (115 kv or above) with a regular member and whose operations have a significant effect on the reliability of the interconnected system of the region. MAIN's regular membership is presently composed of investor-owned, rural cooperative, and municipal power suppliers.

Associated Electric Cooperative has membership in both MAIN and the Southwest Power Pool (SPP); agreement has been reached for Associated to report through MAIN (asterick denotes service operation with the Missouri River Basin) as follows:

Illinois Group

Central Illinois Light Company
Central Illinois Public Service Company
City Water, Light and Power, Springfield
Commonwealth Edison Company
Illinois Power Company
Southern Illinois Power Cooperative
*Western Illinois Power Cooperative, Inc.
*Soyland Power Cooperative
Village of Winnetka
Rochelle Municipal Utilities

Missouri Group

*Associated Electric Cooperative, Inc.
*City of Columbia, Missouri
*Union Electric Company
*Missouri Utilities Company
*Missouri Power and Light Company
*Missouri Edison Company
Wisconsin - Upper Michigan Group
Madison Gas and Electric Company
Upper Pinsula Power Company
Wisconsin Electric Power Company System
Wisconsin Power and Light Company
Wisconsin Public Service Corporation
Kaukauna-Menasha Interconnected Systems
City of Manitowoc
City of Marquette
City of Marshfield

OTHER ORGANIZATIONS

Basin Electric Power Cooperative (BAEP)

Basin Electric Power Cooperative is a regional bulk wholesale power supplier. It serves 8 States and is made up of 165 members including 37 Municipal members. One hundred fifty-seven members are within the Missouri River Basin.

MRB Membership

East River Electric Power Cooperative,
Madison, S. Dak.

Breadle Electric Cooperative, Inc.
Bon Homme Yankton Electric Association
Charles Mix Electric Association
Clay-Union Electric Corporation
Codington Clark Electric Cooperative, Inc.
Douglas Electric Cooperative, Inc.
H-D Electric Cooperative
Intercounty Electric Association, Inc.
Kingsbury Electric Cooperative
Lake Region Electric Association, Inc.
Lincoln-Union Electric Company
Lyon-Lincoln Electric Cooperative, Inc.
McCook Electric Cooperative, Inc.
Northern Electric Cooperative, Inc.
Ree Electric Cooperative, Inc.
Sioux Valley Empire Electric Association
Spink Electric Cooperative
Tri-County Electric Association, Inc.
Turner-Hutchinson Electric Cooperative
Union County Electric Cooperative, Inc.
Whetstone Valley Electric Cooperative, Inc.
Elk Point, S. Dak. (Municipal Member)

L & O Power Cooperative,
Rock Rapids, Iowa

Lyon Rural Electric Cooperative
Osceola Electric Cooperative, Inc.
Southwestern Minnesota Electric Cooperative

Central Power Electric Cooperative, Inc.,
Minot, N. Dak.

Baker Electric Cooperative
Capital Electric Cooperative
James Valley Electric Cooperative
McLean Electric Cooperative
North Central Electric Cooperative
R. S. R. Electric Cooperative
Tri-County Electric Cooperative
Verendrye Electric Cooperative

Northwest Iowa Power Cooperative,
Lemars, Iowa

Cherokee County Rural Electric Cooperative
Harrison County Electric Cooperative
Ida County Rural Electric Cooperative
Monona County Rural Cooperative
Nishnabotna Valley Rural Electric Cooperative
O'Brien County Rural Electric Cooperative
Plymouth Electric Cooperative
Sioux Electric Cooperative Association
South Crawford Rural Electric Cooperative
Woodbury-County Rural Electric Cooperative
Western Iowa Municipal Electric Association

Central Montana Electric G & T Cooperative

Beartooth Electric Cooperative, Inc.
Big Flat Electric Cooperative, Inc.
Fergus Electric Cooperative, Inc.
Glacier Electric Cooperative, Inc.
Hill County Electric Cooperative, Inc.
Marias River Electric Cooperative, Inc.
Northern Electric Cooperative, Inc.
Park Electric Cooperative, Inc.
Sun River Electric Cooperative, Inc.
Tongue River Electric Cooperative, Inc.
Vigilante Electric Cooperative, Inc.
Yellowstone Valley Electric Cooperative, Inc.

Rushmore Electric Power Cooperative, Rapid City, S. Dak.

Black Hills Electric Cooperative, Inc.
Butte Electric Cooperative, Inc.
Cam-Wal Electric Cooperative
Lacreek Electric Association, Inc.
Tri-County Electric Association, Inc.
West Central Electric Cooperative, Inc.
West River Electric Association, Inc.

Upper Missouri G & T Electric Cooperative, Sidney, Mont.

Burke-Divide Electric Cooperative
Goldenwest Electric Cooperative
Lower Yellowstone Rural Electric Assn.
McCone Electric Cooperative
McKenzie Electric Cooperative, Inc.
Mountrail Electric Cooperative, Inc.
Sheridan Electric Cooperative, Inc.
Slope Electric Cooperative, Inc.
Southeast Electric Cooperative, Inc.
Valley Electric Cooperative
West Plains Electric Cooperative, Inc.
Williams Electric Cooperative, Inc.

District No. 9

Mor-Gran-Sou Electric Cooperative
Central Iowa Power Cooperative
Corn Belt Power Cooperative
Cherry-Todd Electric Cooperative, Inc.
Grand Electric Cooperative, Inc.
Moureau-Grand Electric Cooperative, Inc.
Rosebud Electric Cooperative, Inc.
Imperial Public Power District
Brown-Atchison Electric Cooperative Assoc.

Doniphan Electric Cooperative Assoc.
Flint Hills Rural Electric Cooperative Assoc.
Nemaha-Marshall Electric Cooperative Assoc.
Missouri Basin Municipal Power Agency
Heartland Consumers Power District
Nebraska Public Power District

Municipal Members

Anita, Iowa
Adrian, Minn.
Breda, Iowa
Dennison, Iowa
Faith, S. Dak.
Hankinson, N. D.
Harlan, Iowa
Mapleton, Iowa
Milford, Iowa
Miller, S. Dak.
Onawa, Iowa
Orange City, Iowa
Pierre, S. Dak.
Primghar, Iowa
Remsen, Iowa
Rock Rapids, Iowa
Hawarden, Iowa
Howard, S. Dak.
Kimbalton, Iowa
Lake Park, Iowa
Lake View, Iowa
Madison, S. Dak.
Manning, Iowa
Sanborn, Iowa
Sibley, Iowa
Sioux Center, Iowa
Tyler, Minn.
Vermillion, S. Dak.
Volga, S. Dak.
Wall Lake, Iowa
Woodbine, Iowa

Dakotas Electric Cooperative

FEM Electric Cooperative, Inc.
KEM Electric Cooperative, Inc.
Oliver-Mercer Electric Cooperative, Inc.

Tri-State G & T Association, Inc., Denver, Colo.

Bighorn Rural Electric Company
Carbon Power & Light, Inc.
Chimney Rock Public Power District
Garland Light & Power Company
Highline Electric Association
Hot Springs Co. Rural Electric Association, Inc.
K. C. Electric Association
The Midwest Electric Membership Corporation
Morgan Co. Rural Electric Association
Mountain Parks Electric, Inc.
Mountain View Electric Association, Inc.
Niobrara Electric Association, Inc.
Northwest Rural Public Power District
Panhandle Rural Electric Membership Association
Poudre Valley Rural Electric Association, Inc.
Riverton Valley Electric Association, Inc.
Roosevelt Public Power District
Rural Electric Company, Inc.
Sheridan-Johnson Rural Electrification Association

Shoshone River Power, Inc.
Union Rural Electric Association, Inc.
Wheatbelt Public Power District
Wheatland Rural Electric Association, Inc.
Wyrulec Company
Y-W Electric Association, Inc.

Colorado Power Pool (CPP)

The primary purpose of the Colorado Power Pool is the sharing of reserves between four members. Only two of the four members operate within the basin:

MRB Membership

Public Service Company of Colorado
Southern Colorado Power Division-Central Telephone & Utility Corporation

Illinois-Missouri Pool (IL-MO)

The three member pool participates in joint transmission facilities, planning, and development with each other as well as with all adjacent interconnected facilities. All member utilities are members of MAIN.

MRB Membership

Union Electric Company

Associated Electric Cooperative, Inc. (ASEC) withdrew from MAIN in 1980 and is now a part of SWPP.

Inland Power Pool (IPP)

The Inland Power Pool is a thirteen-member coordinating group within the State of Colorado and provides joint planning for reliability. Six members serve the basin:

MRB Membership

Basin Electric Power Cooperative
Public Service Company of Colorado
WAPA Regions 4 & 7
Tri-State G&T Association, Inc.
Platte River Power Authority
Nebraska Public Power District

Intercompany Pool (INTERPOOL)

INTERPOOL is a seven-member operating group within the Northwest Power Pool. The requirements for participation include actual or contractual interconnections with other members of the group. The pool was established for the purposes of coordinating power and energy resources, reserves, transmission facilities, storage, and periodically conducting studies of this nature. Exchange of capacity and energy is permitted within the pool agreement. The pool includes the following two MRB systems:

MRB Membership

Pacific Power & Light Company (PPLC)
The Montana Power Company (MPC)

Iowa Power Pool (IPP)

The Iowa Power Pool is a six-member coordinating group within the State of Iowa and provides for joint planning for reliability in the area. Five members are within the basin:

MRB Membership

Iowa Electric Light and Power Company
Iowa Power and Light Company
Iowa Public Service Company
Iowa Southern Utilities Company
Corn Belt Power Cooperative

Kansas Electric Cooperatives, Inc.

In Kansas, all 38 electric cooperatives belong to the Kansas Electric Cooperatives, Inc. Numerous committees in this incorporated group serve the needs and functions of rural electric cooperatives.

Planning committees study power and energy requirements as well as transmission and distribution needs. This organization also supports the members' interest by lobbying for laws affecting their operations.

Numerous other committees provide information and programs including lineman and job-safety programs, meter service centers, and automated billing service. All the varied interests of electric cooperatives are administered through this umbrella agency.

Kansas Municipal Energy Agency (KMEA)

To arrange long-term power supplies for its members, 14 electric utilities located in the northwest area of Kansas formed the Northwest Kansas Power Agency (NWKPA) in 1972. This agency includes eight municipals, five distribution cooperatives, and one generation and transmission cooperative. During 1979, a group of 18 municipal utilities in eastern Kansas were in the process of organizing the Eastern Kansas Municipal Energy Agency. In January 1980, the two groups merged and formed a single agency that was called the Kansas Municipal Energy Agency (KMEA). About 30 municipal systems of the 64 municipalities in Kansas are members of the KMEA.

Supplemental facilities will be built as determined by the results of the power supply and transmission study. They plan to purchase an 84 MW share of the 280 MW coal-fired generating unit to be constructed by Sunflower Electric Cooperative. The municipal group has an offer to purchase up to 63 MW of the Wolf Creek Nuclear Plant. Additionally, they will study the option of purchasing capacity from the Jeffrey Energy Center. The purchase of this generating capacity and the addition of interconnecting facilities will be financed by the sale of bonds.

These municipal systems presently pay the expenses of the organization through a fee assessment estimated according to the energy consumed by their customers.

Mid-Continent Area Power Pool (MAPP)

MAPP was formed by 22 Midwest generation and transmission systems in February 1963 to promote integrated regional planning. Originally known as the Mid-Continent Area Power Planners, the organization's membership was expanded in 1972, and its present name was adopted. MAPP develops broad plans for expansion of generation and high capacity interconnections. Detailed planning for specific facilities is performed by the individual systems or subgroups that will build or operate them. Current participation in MAPP includes 40 member systems; 20 of which are in the Missouri River Basin.

MRB Membership

1 Federal System

Western Area Power Administration/Billings, Mont.

3 Public Power Districts

Nebraska Public Power District/Columbus, Nebr.
Omaha Public Power District/Omaha, Nebr.

9 Rural Electric G & T Cooperatives

Basin Electric Power Cooperative/Bismarck, N. Dak.
Central Iowa Power Cooperative/Cedar Rapids, Iowa
Cooperative Power Association/Minneapolis, Minn.
Corn Belt Power Cooperative/Humbolt, Iowa
Minnkota Power Cooperative, Inc./Grand Forks, N. Dak.
Northwest Iowa Power Cooperative/LaMars, Iowa
United Power Association/Elk River, Minn.

13 Investor-Owned Electric Utilities

Interstate Power Company/Dubuque, Iowa
Iowa Electric Light and Power Company/Cedar Rapids, Iowa
Iowa Power and Light Company/ Des Moines, Iowa
Iowa Public Service Company/Sioux City, Iowa
Iowa Southern Utilities Company/Centerville, Iowa
Montana-Dakota Utilities Co./Bismarck, N. Dak.
Northern States Power Company/Minneapolis, Minn.
Northwestern Public Service Company/Huron, S. Dak.
Otter Tail Power Company/Fergus Falls, Minn.

14 Municipal Electric Utilities

Fremont, Nebr.
Grand Island, Nebr.
Lincoln, Nebr.

Missouri Basin Municipal Electric Cooperative Association (MBMECA)

The MBMECA membership consists of 13 municipal electric utilities in Iowa; each owns and operates the generator and distribution facilities in its community.

Alton, Iowa	Manilla, Iowa	Sanborn, Iowa
Hartley, Iowa	Orange City, Iowa	Shelby, Iowa
Hawarden, Iowa	Paullina, Iowa	Sioux Center, Iowa
Kimbalton, Iowa	Remsen, Iowa	Woodbine, Iowa

The Missouri Basin Municipal Power Agency (MBMPA)

The MBMPA, a nonprofit, publicly owned organization, is a regional electric wholesale power supplier that serves over 50 municipally owned electric systems in areas of Iowa, Minnesota, North Dakota, and South Dakota with a population of over 200,000. The agency is a member of the Missouri Basin Systems Group (MBSG) and MAPP.

The primary responsibility of MBMPA is to provide a long-term supply of electrical power for its member municipals, 33 of which are in the Missouri River Basin.

MRB Membership

Adrian, Minn.	Manilla, Iowa
Alexandria, Minn.	Orange City, Iowa
Alton, Iowa	Paullina, Iowa
Beresford, S. Dak.	Pierre, S. Dak.
Brookings, S. Dak.	Primghar, S. Dak.
Burke, S. Dak.	Remsen, Iowa
Dennison, Iowa	Rock Rapids, Iowa
Faith, S. Dak.	Sanborn, Iowa
Flandreau, S. Dak.	Shelby, Iowa
Fontanelle, Iowa	Sioux Center, Iowa
Ft. Pierre, S. Dak.	Vermillion, S. Dak.
Hartley, Iowa	Wall Lake, Iowa
Hawarden, Iowa	Watertown, S. Dak.
Kimbalton, Iowa	Winner, S. Dak.
Lake Park, Iowa	Woodbine, Iowa
Lakefield, Minn.	Worthington, Minn.
Luverne, Minn.	

Missouri Joint Municipal Electric Utility Commission (MJMEUC)

The MJMEUC, formed in 1973 and formerly known as the Commission for Municipal Pooling Services, is an organization of 17 municipal electric utilities within Missouri. This group approached the Missouri Legislature in the mid-1970's with their electric power pooling needs and, after some work, obtained from the legislature enabling legislation in 1977 and a Missouri Constitutional Amendment in 1978. The legal authorizations obtained permitted these 17 municipal electric utilities to band together and issue revenue bonds for financing jointly owned power production and distribution facilities.

Currently, an engineering feasibility study is being made for the group by a local consultant. The scope of the study includes site selection and determination of

major characteristics of a new coal-fired steam-electric plant of about 500 MW capacity. High-voltage transmission wheeling arrangements have been worked out with area public electric utility systems.

Presently there are 11 municipals located within the Missouri River Basin:

MRB Membership

Cameron, Mo.	Ownesville, Mo.
Chillicothe, Mo.	Princeton, Mo.
Columbia, Mo.	Springfield, Mo.
Fulton, Mo.	Trenton, Mo.
Independence, Mo.	Waynesville, Mo.
Macon, Mo.	

Missouri-Kansas Pool (MOKAN)

Presently, eight investor-owned utilities and one G & T electric cooperative are members of MOKAN. The Pool agreement, executed on March 28, 1962, provides for the further interconnection of the member systems, the sharing of reserve supply, the exchange of standby service, and continuing operational and administrative relationship to achieve operating economies and reliability through coordinated planning and operation.

In June 1965, three additional contracts (the Missouri Facilities Agreement, the Kansas Facilities Agreement, and the Missouri-Kansas Coordination Agreement) were executed providing the strong 345 kV interconnection facilities to increase interchange capability between the pool's seven members:

MRB Membership

Kansas City Power & Light Company
Missouri Public Service Company
The Empire District Electric Company
Kansas Gas & Electric Company
The Kansas Power & Light Company
Central Telephone & Utilities Corporation - Western Power Division
Central Kansas Power Company

Missouri Basin Systems Group (MBSG)

Early in 1963, the U.S. Bureau of Reclamation and representatives of over 100 preference-type (publicly owned) power systems executed the Missouri Basin Systems Group Pooling Agreement that led to the formation of a power planning group called the Missouri Basin Systems Group (MBSG). (MBSG is concerned with both regional planning and with pooled operation.) Its membership is composed of a large number of municipal electric systems, rural electric cooperatives, and the Bureau of Reclamation. Its two objectives are to achieve coordinated planning for provision of the major power facilities (including thermal generation and high-voltage transmission) required to meet the growing needs of the systems group members beyond those met by the Federal hydroelectric system, and to provide for coordinated operation of the wholesale power supply system. An example of this coordinated effort is the 1,500 megawatt Laramie River bulk power facility currently being constructed in Platte County, Wyoming. When completed, generation from the

plant will be used to meet member system requirements throughout the basin. Thirty-one members of the MBSG's total membership of 46 operate within the basin:

MRB Membership

MUNICIPALS

IOWA

Alta
Anita
Corning
Harlan
Lenox
Millford
Villisca

NEBRASKA

Lincoln

NORTH DAKOTA

SOUTH DAKOTA

Aberdeen

MINNESOTA

STATE AGENCIES

Nebraska Dept. of State Institutions
University of Nebraska

FEDERAL AGENCIES

Department of Energy

DISTRIBUTION COOPERATIVES

Grand Electric Co-op
KEM Electric Co-op
Moreau Grand Electric Co-op
Mor-Gran-Sou Co-op
Oliver-Mercer Electric Co-op

POWER SUPPLY ORGANIZATIONS

Basin Electric Power Co-op
Central Montana G&T
Central Power Electric Co-op
East River Electric Power Co-op
L & O Power Co-op
Missouri Basin Municipal Power Agency
Nebraska Electric G&T
North Central Kansas Power Agency
North Dakota Municipal Power Agency
Northwest Iowa Power Co-op
Rushmore Electric Power Co-op
Sunflower Electric Co-op
Tri-State G&T Association
Upper Missouri G&T

Note: More than 30 municipal members of MBMBA are also signatories of the MBSG Pooling Agreement.

Nebraska Municipal Power Pool (NMPP)

The NMPP, formally organized on January 1, 1976, as a nonprofit municipal corporation under Nebraska laws, is an organization of Nebraska municipal electric systems. The NMPP was formed by the municipals to coordinate, operate, and provide facilities as needed and determined by members of the corporation. The NMPP's first announcement called for plans for "initial studies that could lead to the construction of a large electrical generating plant or joint participation with others in facilities in Nebraska within the next few years."

At present, NMPP controls a small amount of diesel capability by telephone and teletype from its control center at Lincoln, Nebraska; however, a pooling agreement is now being prepared to provide economic dispatch of generation among the participating members. The NMPP has a transmission agreement with Omaha Public Power District and is negotiating a similar agreement with Nebraska Public Power District that will facilitate interaction of the generation resources from other utilities or future plants of NMPP. All members are in Nebraska and within the basin.

Alliance, Nebr.	David City, Nebr.	Mullen, Nebr.
Alma, Nebr.	Fairbury, Nebr.	Nebraska City, Nebr.
Ansley, Nebr.	Falls City, Nebr.	Neligh, Nebr.
Auburn, Nebr.	Fremont, Nebr.	Oxford, Nebr.
Bayard, Nebr.	Gering, Nebr.	Pender, Nebr.
Beatrice, Nebr.	Grand Island, Nebr.	Plainview, Nebr.
Benkelman, Nebr.	Grant, Nebr.	Shickley, Nebr.
Blue Hill, Nebr.	Hastings, Nebr.	Sidney, Nebr.
Bridgeport, Nebr.	Kimball, Nebr.	St. Paul, Nebr.
Broken Bow, Nebr.	Lincoln, Nebr.	South Sioux City, Nebr.
Cambridge, Nebr.	Lyman, Nebr.	Syracuse, Nebr.
Chappel, Nebr.	Maddison, Nebr.	Tecumseh, Nebr.
Crete, Nebr.	Mitchell, Nebr.	Wahoo, Nebr.
Curtis, Nebr.	Morrill, Nebr.	West Point, Nebr.

Nebraska Pool (NEP)

Nebraska once led the Nation in the number of municipally owned electric systems. Due to the economies of large, central station service, and the efforts of investor-owned utilities, many municipally-owned systems were acquired, integrated, and interconnected through transmission facilities. This trend continued following the acquisition of the investor-owned utilities' properties by public power districts. Nonetheless, in 1958, 65 cities and towns in Nebraska owned generating plants, the majority of which were not interconnected with the systems of the large public power districts.

Both Omaha Public Power District and Nebraska Public Power District were original signatories to NMPP. Some of the benefits accruing as a result of participation in the pool are the following:

1. Greater reliability of service through the establishment of operating procedures and criteria.

2. Economic savings through coordinated plans of transmission and generation.

3. Reduced costs of operation through coordinated relationships in NMPP including reduced reserve requirements, advantageous energy exchanges, availability of peaking energy, and improved load factors.

4. Enlarged market for surplus power sales.

5. Beneficial interchange of views and information in committee participation.

6. Economics of seasonal diversity exchanges.

7. Beneficial continued studies and research.

Although quantifying in dollars the benefits to Nebraska utilities from participation in NMPP is difficult, significant economies have accrued.

North Iowa Municipal Electric Cooperative Association (NIMECA)

The North Iowa Municipal Electric Cooperative Association was organized as a corporation under the Iowa cooperative laws in 1965. A headquarters office was established in Humboldt, Iowa, in December 1977. Membership consists of 17 municipals; each owns and operates generation and distribution facilities in its communities. The NIMECA was formed to provide lower cost power from larger generating sources. Most of the members purchase power from Corn Belt Power Cooperative with deliveries via the Corn Belt transmission system.

Eight of NIMECA's members have purchased an undivided interest (48 MW) in the Neal #4 Unit in Sioux City, Iowa. The Iowa Public Service Company is the project manager of this unit, which has a total installed capacity of 576 MW and began commercial operation on July 1, 1979. Output of Neal #4 is delivered to NIMECA members over transmission facilities owned and operated by a group of investor-owned utilities and also over the Corn Belt system.

The NIMECA is also a member of a new group, Allied Power Cooperative, organized to obtain additional generating capacity in the late 1980's. Only two cooperatives are located within the Missouri River Basin.

MRB Membership

Alta, Iowa
Spencer, Iowa

Northwest Power Pool (NWPP)

The purpose of the Northwest Power Pool is to make the best use of available facilities. Each member system prepares and circulates a weekly report containing information regarding load-supply situation, water conditions, fuel supply, maintenance schedules, and other conditions that might affect pool operations. The Operating Committee and Coordinating Group agrees on principles and procedures for maintaining frequency and interchange control, interchange scheduling and accounting, maintenance schedules, relay settings, communications systems, generating reserves, reactive resources, voltage compensation, and other items affecting pool operation.

An outgrowth of the operating program of the NWPP is load shedding by under frequency relays, so that area loads are matched to area generation, and in case of a major disturbance, generation may be maintained and load restored in an orderly and timely manner.

NWPP membership is comprised of 25 U.S. systems and 3 Canadian systems, but only 4 provide basin service:

MRB Membership

Bonneville Power Administration
Idaho Power Company
Montana Power Company
Pacific Power & Light Company

Pacific Northwest Coordination Agreement (PNCA)

The PNCA group coordinates the operation of power resources and transmission facilities under a long-term (35 years) agreement executed in 1964 between 16 signatory parties. The group determines the firm loan carrying capability of the interconnected systems in accordance with the provisions of the agreement and makes studies and plans of the coordinated operation for the advice and information of the members. The agreement provides for interchange of energy, for storage of energy, and for payments and entitlements between upstream and downstream plants. It also provides for coordination of the use of transmission facilities and charges for energy transfers. The coordinated planning of maintenance outages is provided. The amount and extent of system participation in providing for forced outage reserve, energy reserve, and spinning reserve is established by the group. Missouri River Basin signatories to the PNCA are as follows:

MRB Membership

Bonneville Power Administration
The Montana Power Company
Pacific Power & Light Company

Pacific Northwest Utilities Conference Committee (PNUCC)

PNUCC is an informal organization comprised of representatives from 25 utilities in the Pacific Northwest. Activities of PNUCC are primarily concerned with:(1) reviewing the plans and programs of the Federal agencies and providing support for needed power projects and transmission facilities where Federal appropriations are required, and (2) evaluation of loads and resources on an overall forecast basis.

The annual power loads and resources report prepared under the sponsorship of PNUCC is known as the "West Group Forecast." This report compiles the load forecasts of all the utilities included in the West Group of the Northwest Power Pool. These 10-year forecasts include a comparison for each year of estimated loads with existing and scheduled generating plants.

Missouri River Basin membership in PNUCC consists of two systems:

MRB Membership

The Montana Power Company
Pacific Power & Light Company

Platte River Power Authority (PRPA)

The Platte River Power Authority is a four-member planning and operating group. It is involved in the construction of transmission facilities to provide delivery of power to its members and participation by the members in the construction of jointly owned coal-fired generating plants:

MRB Membership

City of Fort Collins, Colo.
City of Loveland, Colo.
City of Longmont, Colo.
City of Estes Park, Colo.

Rocky Mountain Power Pool (RMPP)

RMPP was formed primarily for the purpose of coordinating operations of member systems. The pool is informal in that there is no master contract to which all members are signatory. However, there are numerous two-party and some three-party contracts that enable various power transactions to take place between the members of the pool. The pool is operated under the overall direction of a Policy Committee, with day-to-day operation supervised by an Operating Committee. The Operating Committee is responsible for maintenance coordination, enforcement of operating guides, reliability of the bulk power system, and reviewing the status of load growth and new facility construction. The pool has been particularly effective in coordinating Bureau of Reclamation hydroelectric generation and the thermal production of other pool members. The RMPP is composed of 14 systems, of which the 11 operate within the basin:

MRB Membership

Black Hills Power & Light Company
Cheyenne Light, Fuel & Power
Montana Power Company
Nebraska Public Power
Pacific Power & Light Company
Platte River Power Authority
Public Service Co. of Colorado
So. Colorado Power Division - Control Telephone & Utilities Corp.
Tri-State Generation & Transmission Assoc., Inc.
WAPA - Lower Missouri Division
WAPA - Upper Colorado Division
Bureau of Reclamation

South Dakota Municipal Power Agency (SDMPA)

The SDMPA, consisting of six municipalities in the State of South Dakota, has legal authority to plan, acquire, construct, operate, and maintain projects to meet its members' utility needs.

MRB Membership

Beresford
Brookings
Ft. Pierre
Pierre
Vermillion
Watertown

South Iowa Municipal Electric Cooperative Association (SIMECA)

The South Iowa Municipal Electric Cooperative Association, which has 17 members, was formed in 1969-70. Initially, six cities joined. All but one had individual generation facilities. Since that time, membership rules have been changed so that all subsequent members must have generation facilities to qualify for membership.

Before the formation of SIMECA, certain members were purchasing power from Central Iowa Power Cooperative (CEIC) as single systems. Total purchases, however, were restricted in magnitude because of a limit on the cooperative's nonmember revenue. Since the organization of SIMECA, which is classified as a cooperative, the limitation no longer applies to SIMECA's purchases from CIPCO.

The SIMECA assesses all members taking power from CEIC according to their purchases. This assessment pays for an outside consultant's fee for a load study on each city. Results of the study will determine the extent to which members may participate in a baseload capacity addition currently under study by CEIC. Six of the members serve the Missouri River Basin:

MRB Membership

Corning, Iowa
Fontanelle, Iowa
Greenfield, Iowa
Lennox, Iowa
Lamon, Iowa
Villisca, Iowa

Southwest Power Administration (SPA)

The Southwest Power Administration (SPA) was established by the Secretary of the Interior under responsibilities delegated by section 5 of the Flood Control Act of 1944. This agency, with headquarters in Tulsa, Oklahoma, was designated as the marketing agent for 24 hydroelectric projects constructed by the U.S. Army Corps of Engineers. The Clarence Cannon Project is scheduled to be in operation in 1982.

The energy from the SPA is marketed to rural electric cooperatives, municipals, government installations, industrial customers, and private utilities. The project marketing area of this agency is located in parts of the six-State areas of Arkansas, Kansas, Louisiana, Oklahoma, Missouri, and Texas.

Upper Mississippi Valley Power Pool (UMVPP)

The initial UMVPP agreement was signed in 1961 and the UMVPP consists of 12 members, 6 of which serve the Missouri River Basin:

MRB Membership

Cooperative Power Association
Interstate Power Company
Minnkota Power Cooperatives, Inc.
Montana-Dakota Utilities Company
Northern States Power Company
Northwestern Public Service Company
Otter Tail Power Company
United Power Association

Western Iowa Municipal Electric Cooperative Association (WIMECA)

As of the end of 1980, six member systems had entered into a formal agreement to purchase a 16 MW share to Northwest Iowa Power Cooperative's 100 MW interest in the Neal #4 unit. This commitment also covers agreement for connecting transmission from the Neal #4 unit through the Northwest Iowa Power Cooperative System. Northwest Iowa Power Cooperative is also the supplier of WAPA power to these municipal systems.

MRB Membership

Anthon, Iowa
Aurelia, Iowa
Manning, Iowa
Mapleton, Iowa
Onawa, Iowa

Western Minnesota Municipal Power Agency (WMMPA)

The Western Minnesota Municipal Power Agency consists of 19 municipalities in the State of Minnesota. This agency is a municipal corporation and political subdivision of the State of Minnesota and is deemed to be performing an essential governmental function exercising a part of the sovereign powers of the State of Minnesota in its utility undertakings on behalf of its members. It has the legal authority to plan, acquire, construct, operate, and maintain one or more bulk power projects within or outside of the State of Minnesota or to acquire interests in or rights to capacity of such projects. It may act as agent or contract with someone else to perform any act authorized to it in connection with such project matters.

To meet its obligations, WMMPA has issued and sold Power Supply Revenue Bonds for the purpose of financing (1) its 7.6-percent share of the Missouri Basin Power Project--a three-unit 1500 MW coal-fired steam-electric generating plant now under construction near Wheatland, Wyoming, and related water supply and transmission facilities; (2) a 60 MW combustion turbine located in Watertown, South Dakota; and (3) its share of certain additional transmission facilities that consist of 5.5 miles of double circuit 345 kv transmission line and associated switching and substation facilities. There are 3 member towns of WMMPA in the Missouri River Basin.

MRB Membership

Adrian, Minn.
Luverne, Minn.
Worthington, Minn.

APPENDIX 2

STATEWIDE TOTAL OF GENERATING UNITS OF MEMBER STATES

December 1979

SUMMARY FOR THE STATE OF COLORADO

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	343.0	1	0.0	0
Coal	3271.2	27	6234.0	12
Oil	792.3	60	0.0	0
Gas	295.6	39	0.0	0
Water	776.4	42	1011.0	5
Other	0.0	0	0.0	0
Unknown	0.0	0	0.0	0

SUMMARY FOR THE STATE OF IOWA

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	597.0	1	0.0	0
Coal	4791.1	80	2707.0	6
Oil	1326.2	257	25.0	1
Gas	184.1	40	0.0	0
Water	134.6	24	0.0	0
Other	0.0	0	0.0	0
Unknown	269.0	169	0.0	0

SUMMARY FOR THE STATE OF KANSAS

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	0.0	0	1150.0	1
Coal	2647.0	9	3045.0	6
Oil	802.3	283	34.0	2
Gas	4187.9	188	0.0	0
Water	2.1	7	0.0	0
Other	0.0	0	0.0	0
Unknown	0.0	0	0.0	0

SUMMARY FOR THE STATE OF MINNESOTA

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	1755.0	3	0.0	0
Coal	4473.3	62	1150.0	3
Oil	1542.5	214	34.0	2
Gas	61.0	19	0.0	0
Water	145.9	62	0.0	0
Other	35.0	5	0.0	0
Unknown	163.3	113	0.0	0

SUMMARY FOR THE STATE OF MISSOURI

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	0.0	0	2384.0	2
Coal	10265.3	54	2607.0	5
Oil	1585.4	131	858.0	13
Gas	1161.3	75	0.0	0
Water	929.0	24	54.0	2
Other	0.0	0	0.0	0
Unknown	91.0	60	0.0	0

SUMMARY FOR THE STATE OF MONTANA

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	0.0	0	0.0	0
Coal	939.0	4	1556.0	2
Oil	134.2	8	0.0	0
Gas	30.0	3	0.0	0
Water	1772.4	80	463.0	8
Other	14.0	3	0.0	0
Unknown	0.0	0	0.0	0

SUMMARY FOR THE STATE OF NEBRASKA

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	1338.0	2	0.0	0
Coal	2367.5	20	1485.0	4
Oil	688.9	77	0.0	0
Gas	443.7	79	0.0	0
Water	145.5	27	1336.0	8
Other	0.0	0	0.0	0
Unknown	146.4	108	0.0	0

SUMMARY FOR THE STATE OF NORTH DAKOTA

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	0.0	0	0.0	0
Coal	2263.2	15	1840.0	4
Oil	100.0	45	0.0	0
Gas	2.0	1	0.0	0
Water	400.0	5	0.0	0
Other	0.0	0	0.0	0
Unknown	0.0	0	0.0	0

SUMMARY FOR THE STATE OF SOUTH DAKOTA

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	0.0	0	0.0	0
Coal	488.0	8	0.0	0
Oil	435.1	66	28.0	1
Gas	0.6	2	0.0	0
Water	1480.9	28	0.0	0
Other	0.0	0	0.0	0
Unknown	32.0	31	0.0	0

SUMMARY FOR THE STATE OF WYOMING

Primary Fuel	Existing Capacity MW	Total Number of Existing Units	Projected Capacity MW	Total Number of Projected Units
Nuclear	0.0	0	0.0	0
Coal	3417.9	18	3080.0	7
Oil	16.3	15	0.0	0
Gas	16.0	1	0.0	0
Water	221.2	26	0.0	0
Other	0.0	0	0.0	0
Unknown	0.0	0	0.0	0

Source: Inventory of Power Plants in the United States December 1979, U.S. Department of Energy